Fundamentals of Energy Regulation

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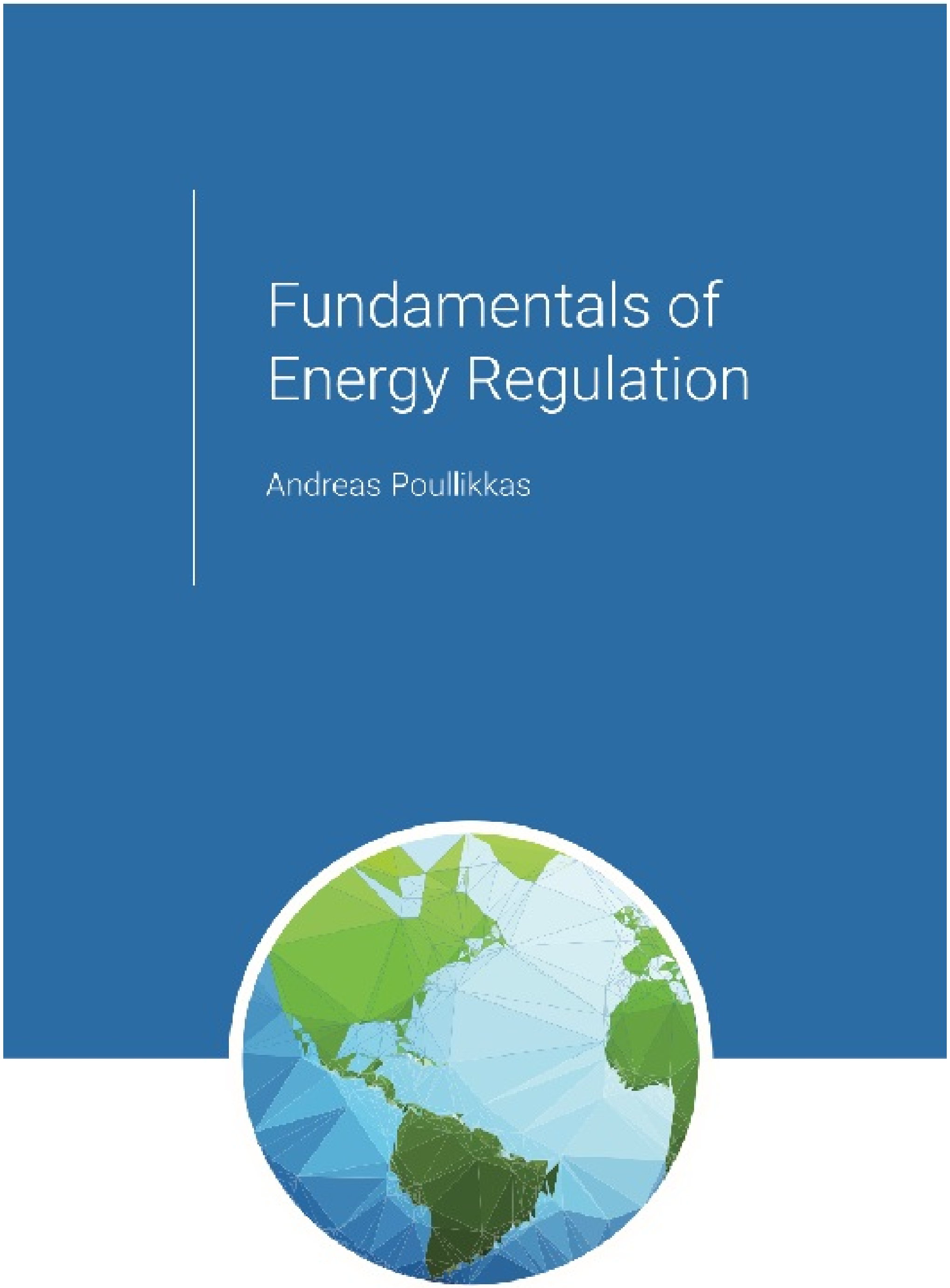

Fundamentals of

Energy Regulation

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“Science is nothing but perception”

Plato (427 BC – 347 BC)

To the two most important women in my life

Preface

Fundamentals of Energy Regulation provides an insight to the wide range of topics necessary for energy regulators. Is a complete introduction to the world of energy regulation and provides the fundamental aspects of each energy regulat of key economic and regulatory concepts.

Fundamentals of Energy Regulation covers emerging issues associated with restructured electric energy and capacity markets as well as international prac-tises affecting the natural gas and electric industries. Provides the various aspects and steps of managing the transition to energy market competition and for the development of energy tariffs.

Fundamentals of Energy Regulation, also, provides an insight to the wide range of electricity generating technologies including renewable energy sources available today or under development, an overview of the future sustainable energy systems and environmental issues.

The topics are presented in an easily digestible form. The book gives a clear, unbiased overview of the energy regulation fundamentals. The book is divided into nine chapters as follows:

- Chapter 1: Energy Regulation.
- Chapter 2: Energy Markets.
- Chapter 3: Capacity Markets.
- Chapter 4: Electricity Sector Reforming.
- Chapter 5: Energy Markets Competition.
- Chapter 6: Energy Tariffs.

- Chapter 7: RES Technologies for Power Generation.
- Chapter 8: Future Sustainable Energy Systems and Methodologies.
- Chapter 9: Pricing Environmental Pollution.

Fundamentals of Energy Regulation is partly based on lecture notes provided in t introductory textbook for courses in the field of energy regulation and energy markets. It is not by any means exhaustive, nor is it intended to be. In the

more than two decades I've worked with the energy industry, the field has grown so vast that it's no longer possible to confine all aspects within the covers of one book, even after limiting it to the most important issues.

Fundamentals of Energy Regulation can serve as a reference text for energy regulators, power and natural gas market planners, utility managers, transmission makers and economists.

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Nicosia, Cyprus

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Chapter 1

Energy Regulation

Effective protection of the property rights of investors and a framework of known legal rules are conducive to stronger economic development. However, simply transplanting legal and regulatory models to other countries is often inadequate to respond to the different circumstances in these countries. A legal or regulatory system may need to be designed differently for each country, so as to take all individualities into account.

Generally, respect for basic property and contract rights and an independent judic politicians is key to an effective legal and regulatory system. However, there is no perfect regulatory system. Continuous improvements and adjustments are necessary as it adapts to internal and external changes. A good regulatory system the process of reform is still underway, therefore a regulatory agency's structure r and market conditions.

In addition, appropriate clarity of the relationship between government and regulator, including definitions in the governing legal framework, is crucial to good regulation and reduction of investor risks. Also, political will must exist, which will allow regulators to do their jobs. Overall, there are three basic principles on which a regulatory system must be built: (a) independence,

(b) transparency, and

(c) investor and consumer protection.

The importance of achieving a degree of regulatory independence, although controversial at times, cannot be underestimated. Independence is crucial to the regulator's task. Transparency is the key to attracting and retaining efficient in and the regulator to set fair policies both now and in the future. Absence of regulatory transparency can severely undermine investor confidence.

Furthermore, it is the role of energy regulator to strike the balance between encouragement of investors and consumer protection. A regulatory agency must support investment by protecting investors from arbitrary government actions but also protect consumers from abuse by firms with substantial market po essential for delivering on its mandate, whether this is in terms of:

• laws,

• financial resources, and

• high quality staff.

There is no quick and easy energy regulatory model that can be applied.

However, there are some best practice principles emerging from international experience that can provide guidelines to governments wishing to establish regulatory agencies. Emphasis should always be given to the independence of the energy regulator from external influence sos as to ensure the establishment of credible and transparent regulatory decisions that will foster confidence and legitimacy in the eyes of investors and consumers alike.

Whilst the varying natures of energy sectors, of political structures and of legacy arrangements in different countries mean that functions of energy regulators differ, they have, in common, the same general purpose:

• to monitor competition in the energy market,

• to assist in the implementation and development of national and international er

• to assist in the commercial development of energy sectors, particularly with regard to deregulation and wholesale markets.

They can also act as:

• policy implementer,

• policeman,

• watchdog,

• instrument of industry accountability,

• communicator, and

• international policy integrator.

In setting up an energy regulator, there are a number of steps to be taken, including establishing regulator’s legal mandate, designing the basic values and principles with which the regulator will apply the regulatory process, establishing the core functions of the regulator and distinguishing them from the functions of government ministries, deciding on the operational structure and hiring qualified and experienced staff.

Overall, a well functioning regulatory agency needs adequate resources, an appropriate legal mandate and clear agency values and operating procedures.

Energy regulators can be funded by taxes, or by levies to the energy market, mainly through price regulated entities.

1.1

Principles of energy regulation

1.1.1

Independence

Regulatory autonomy or independence usually means having a regulatory body that is free from influence from external sources in its decision making.

Often this means independence or autonomy from the government. Ensuring that political oversight is not seen to impede the functioning of the regulator can be crucial in establishing the credibility of a newly created regulator.

However, it is commonly accepted that balancing regulatory autonomy and/or independence with sustainable financing of regulatory agencies is a difficult task and there is seldom a perfect answer. Sometimes, the principal source of financing for many regulators is the government, leaving them at least partly vulnerable to political influence.

One way suggested to partly mitigate the issue of dependence on government fun fenced funding for the regulator. However, Fundamentals of Energy Regulation

reduced independence of a newly established regulatory agency may be necessar is established and other stakeholders learn about the processes used by the regulator.

Further, the only way an energy regulator can be truly independent is if it has been provided with the tools and resources essential for delivering on its mandate. A weak regulator, for example, in terms of financial or human resources, will find it very difficult to remain autonomous.

There are a number of different regulatory models with respect to energy regulator independency:

Fully independent: Regulators are civil servants and independent of any ministry. As a result they can find themselves in conflict with ministries,

as indeed the ministries can find themselves in conflict with each other.

The independence gives the regulator a substantial de facto role in policy formulation.

Regulator as ministerial advisor: The regulator is attached to a ministry, and advises on, rather than formulates policy solutions.

Light handed regulation: The industry substantially self governs, and market inte

Competition authority as regulator: Not being attached to a ministry, the regulator is very similar to an independent regulator, although with a greater emphasis on competition and market development, relative to policy implementation.

Self regulation: The presence of a regulator independent of the industry is generally regarded as essential and hence pure self regulation is becoming less common.

Regulators do not have exclusive control over the industry. For example, the competition authority, international competition law, international agreements is natural for there to be some tensions between the objectives of the energy regulator and that of the other bodies.

1.1.2 Transparency

Transparency means transparent regulatory decision–making and robustness, expediency, quality and predictability of regulatory decision–making. The following might be regarded as a wide and dynamic definition of the concept of regulatory transparency:

Transparency is defined as tools and measures that foster confidence in and unde

Regulatory transparency is more important in weak institutional environments wi
regulatory process to stakeholders promotes legitimacy. However, it is recognizec
requirements of investor confidentiality. In brief, transparency:

• Is crucial to the legitimacy of the regulatory process,

• Is the key to attracting and retaining efficient investment,

• Creates confidence in the credible commitment from the government and the regulator to a set of fair policies both now and in the future,

The financial impact of the absence of regulatory transparency is potentially vast
the regulator to promote transparency is to prepare and distribute to stakeholders
sector performance.

1.1.3 Investor and consumer protection

The basic role of the regulator is to balance the interests of three stakeholder groups:

• the government,

• the electricity (or energy) service suppliers, and

• the customers.

Each of these groups has potentially conflicting interests. The government is subject to short–term political pressures from various constituencies. For investors to commit to long–term investments, the regulator must be free from undue influence. For example suppliers want high returns, and an unchecked, non–regulated, monopolist will charge too high a price. Customers, conversely, want reliable electricity at low prices.

Therefore, a key element of the regulator’s role is striking the balance between encouraging investors and protecting consumers, while fulfilling govern has the obligation (via licensing) to provide a service under the approved tariffs and quality standards.

Consumers have an obligation to pay for that service to ensure the financial viability of the sector. For example, the review of tariffs and costs, one of the core functions of a regulator, is central to protecting consumers and facilitating investment. The energy regulator must, also, be wary of the emergence of monopolies that might have enough influence to set higher prices than those of competitive market prices.

The purpose of regulation is to ensure that price reflects the least cost of service, given mandated quality and reliability standards. The role of the regulato term objectives established by the government,
while balancing the interests of all three stakeholder groups (government, supplie term sustainability of the sector depends on
looking beyond the immediate interests of each of the groups.

1.2

Different bodies involved in energy regulation Various governmental and non–governmental bodies can be involved in the activity of regulation. The independe model for regulation of the energy industries. This is common in many countries an independent energy regulatory body as part of that process.

However, this is not the only model, In some countries, even where the industry has been privatized, a central government department can retain either the whole regulatory function or parts of it. In this case, electricity is typically regulated by a ministerial agency, usually under the Ministry of

Energy.

Whether it is an independent regulator or a government department who has the primary role, there will often also be other bodies with a role in

regulating the energy industry. The following bodies can all be involved in regulating the energy industry:

• Central government departments,

• Energy regulatory agencies,

• Generalist competition regulators,

• Environmental regulators,

• Local authorities,

• Courts and tribunals.

1.2.1

Central government departments

Where central government departments are directly involved they make regulatio control and legitimacy. Whether or not this is considered desirable will depend up

For example, there may be concerns that governments may be willing to compror pressures to protect companies from competition to preserve jobs.

1.2.2

Energy regulators

One of the main arguments made in the favour of specialist utility or energy regulators is that, where the agency enjoys reasonable independence from govern damage economic efficiency. The main argument against is lack of accountability a group of individuals where a commission-type structure exists) who may pursue policies that are at odds with government policy or publicly mandated policy goals. These regulators are generally subject to a set of duties provided by legislation, although the legislation may provide for a considerable degree

of discretion on the part of the regulator in applying and balancing these duties. A
is thus one of the key challenges.

1.2.3

Generalist competition regulators

The generalist competition regulator's role is to take action against activities that may hamper competition in any sector of the economy. Typically they will have a role in assessing whether certain mergers should be allowed to proceed and in taking action where companies with market power are found to be acting anti–competitively.

1.2.4

Local authorities

Local authorities may have two types of role. Firstly in planning control, e.g., in the siting of energy facilities such as power stations, wind turbines, etc.

Secondly, in some countries, local authorities provide municipal electricity and/or heat (district heating) supply. These companies may be regulated by a sector regulator where one exists or they may be largely self–regulatory.

1.2.5

Courts and tribunals

The position of courts and tribunals can vary somewhat, depending on the particular structure. In some systems they are empowered to act as the point of last appeal on disputes between other regulatory bodies and companies. In other systems, courts and tribunals can be the first point of call concerning company behaviour.

1.3

The role of energy regulator

1.3.1

The need to regulate the electricity sector
Below, the importance of electricity sector regulation is provided (although the same principles can apply to other sectors also):

• To constrain the exercise of monopoly power by incumbent suppliers,

• To provide incentives for operating efficiency and quality of service,

• To optimize the structure of the sector,

• To promote least–
cost system expansion including private capital invested in independent power pr

• To stimulate energy conservation and R&D.

1.3.2

The purpose of a regulator

The purpose of a regulator is often seen as balancing of interests but unless benefits are also created under the regulatory regime (i.e., improved sector perfor
is:

• To protect consumers from abuse by firms with substantial market power,

• To support investment by protecting investors from arbitrary government action

• To promote economic efficiency.

Under a regulation–by–contract regime and potentially having to engage in contract re–negotiations, the regulator's role will increasingly be that of honest broker or even impartial player focused on creating solutions and building consensus between service providers/investors and governments.

1.4

1.4.1

Designing a regulator

A well functioning regulatory agency needs adequate resources, an appropriate legal mandate as well as clear agency values and operating procedures. This is by no means an easy or straightforward task and a number of questions can be raised when thinking of how to set up a regulator. Some of these are listed below:

• Legal mandate

–
 Should the regulator have jurisdiction over one industry? One sector? Or many s

– What are the functions of the regulator and what are those of the ministries?

– After establishment, at what point and how should revisions be made to the law?

• Values

– If independence is important, how can it be achieved?

– What processes will promote transparency?

– What kind of information does the regulator require in order to be able to make informed decisions?

• Resources

– Consideration of resources affects start–up strategy,

– What kind of leadership is required (individual or committee)?

–
How does funding, recruitment of professionals, and staff development affect the

What is suggested to be defined first are the key objectives, against which the regulator's success will later be judged. Then the values and principles to be applied in the regulatory process as well as the functions that need to be assigned and implemented need to be defined. Then a process that will ensure that decision–making is transparent need to be designed.

1.4.2 Resources

One of the often–neglected reasons why regulation models may not work is because of a lack of available resources. A regulatory system may well need to be designed differently where the resources available for investment in it are more limited. It must not be forgotten that while creating laws and rules is relatively straight forward, creating new institutions with roles in regulation requires relatively heavy investment in terms of labour costs. Therefore, a policy of selecting rules and regulations that reduce institutional costs would seem logical.

When discussing availability of resources, it should be born in mind that the term resources could mean many things. The term should not be understood i
more:

• Manpower to monitor, conduct, process and enforce rules and sanction systems;

• Investment in information technology to facilitate communication and therefore also the effectiveness of decision–making;

• Human capital, where average lower educational achievement affects both the quality of decision–making by officials and the ability of ordinary citizens to initiate or contribute to the enforcement process.

These resources are necessary for an effective regulator to exist, therefore when they become constrained or limited, this should not be ignored but action should be taken to create solutions or adapt the existing system, so it may continue to be effective. The following are suggestions for adapting a regulatory regime to ease the pressure on limited resources:

• Regulatory goals may be more effectively pursued if they coincide, or are compatible, with community norms.

• If the regulatory regime can in some way be identified with, or internalized by, the community, whether within or outside traditional law, this will facilitate monitoring and enforcement, both of which are heavily resource intensive.

• Sanctions often fail to be effectively applied due to corruption or simply insuffic

In the later case, there is an understandable reluctance to impose imprisonment as the principal alternative to paying of fines, especially for minor offences. Therefore, in some cases it may be more cost effective for regulatory systems to focus their enforcement efforts less on those who actually contravene the rules but have insufficient wealth to pay penalties (e.g., an individual who fails to pay an electricity bill) and more on third parties who can control the contravener's conduct and do have sufficient assets for financial penalties to be effective as a deterrent. So, for example, a firm in the expectation that it can apply effective informal sanctions on their employees. In some developing country contexts, the same idea might be extended to render the extended family or community responsible to equivalent effect.

• Using discretion instead of rules in decision–making is also a way to

reduce bureaucracy and complex rule–making by leaving decisions in the hands of informed individuals. However, this has two disadvantages: first, the exercise of discretion requires greater knowledge and expertise than simple application of rules and, secondly, discretion can be exploited more easily than rules for the purposes of corruption.

1.4.3

Legal mandate

The functions of a regulator are usually defined in primary legislation. Changes to regulatory functions are also usually implemented through primary legislation.

There must be a clear mandate and the tools and means to implement that mandate should be made available to the regulator.

A regulator’s work will include, amongst other functions:

- issuing licences,
- setting performance standards,
- monitoring the performance of regulated firms,
- establishing the level and structure of tariffs,
- arbitrating disputes among stake–holders, and
- reporting sector and regulator activities to the appropriate government authority.

For each of these functions, the regulator needs sufficient legal authority to carry out its responsibilities.

1.4.4

Values and principles

The values and principles a regulator decides to use to apply the regulatory process are important, as these will determine whether credibility with the investment community, legitimacy for consumers and strong incentives for

economic efficiency are established. A review of international best practice principles for regulatory commissions is provided below:

Communication: information should be made available to all stakeholders on a timely and accessible basis. Consultation: participation of stakeholders in me

Consistency: the logic, data sources, and legal basis for decisions should be consistent across market participants and over time.

Predictability: a reputation for predictable decisions facilitates planning by suppliers and customers, and reduces risk as perceived by the investment community.

Flexibility: the agency should use appropriate instruments in response to changing conditions, balancing this regulatory discretion against the costs associated with uncertainty.

Independence: autonomy implies freedom from undue stakeholder influence, which promotes public confidence in the regulatory system.

Effectiveness and efficiency: cost effectiveness should be emphasized in data collection and in the policies implemented by the regulator.

Accountability: regulators should provide clearly defined processes and rationales

Transparency: the openness of the process to stakeholders promotes legitimacy.

These principles should be incorporated in the regulatory process for effective im component includes a procedure for appeal to a regulatory decision.

1.4.5 Functions

A review of experience around the world indicates that the following constitute

the key regulatory functions in the electric power sector:

• Issuing licences related to regulatory functions,

• Setting performance standards,

• Monitoring the performance of regulated firms,

• Establishing the level and structure of tariffs

• Establishing a uniform accounting system,

• Arbitrating disputes among stakeholders,

• Performing (usually via an independent consultancy) management audits on reg

• Developing human resources,

• Reporting activities to the appropriate government authority[1].

All of these functions have implications for the central objectives of regulation, su on continuing to attract needed capital investment for the sector. Interrelationships among the functions affect costs and tariffs. Often rate re–balancing (to reduce cross–subsidies from particular customer groups) or rate increases (to bring prices up to costs) are objectives of reform, and the creation of a regulator clearly involves a review of costs and tariffs.

Issuing licences is often one of the first actions undertaken by a new regulator. A of goods or services. Licensing systems are relatively expensive to administer, however they have proved a popular instrument amongst regulation agencies.

The popularity of licensing systems can be explained for the following reasons, amongst others:

• Weak monitoring systems (due to lack of human and financial resources),

• Easy method for revenue raising through registration and licensing fees (easier and more acceptable than taxation),

• Less prone to corruption.

However, some problems remain with the cost of this approach, especially since companies still have to be monitored post–licensing to ensure they do not subsequently default on their licence conditions.

1In the case of European Union Member States reporting is, also, required to the Commission.

1.4.6 Operational structure

Agreed regulatory functions largely determine the design of a regulatory body’s organizational structure. Figures 1.1 and 1.2 display two models of organizational member commissions.

Chairman and

members

(commissioners)

Executive

Director

Management

Engineering

Accounting

Legal

services

Department

Department

Department

Department

Department staff

Department staff

Department staff

Department staff

Figure 1.1: Organizational model A: multi–member commission.

Under model A, shown in Figure 1.1, the chairman and members concentrate on making, while the professional preparatory work and due–

diligence effort is done under the supervision of an appointed executive director.
on
managerial roles, and head the individual functional departments. It is possible to
commissioners. An additional option is to have an external consultation committe
decisions and inform the ministries of sector developments.

Whether commission members are full or part–
time, their actual professional background, and their status in terms of seniority, a
that might affect which model is chosen. For example, if members work full–

time, model B might be appropriate. Members who lack professional expertise

Chairman

Commissioner

Commissioner

Commissioner

Commissioner

Management

Engineering

Accounting

Legal

services

Department

Department

Department

Department

Department staff

Department staff

Department staff

Department staff

Figure 1.2: Organizational model B: specialized responsibilities.

or who are very senior may not want to head the relevant departments as required

While an odd number of commissioners, including the chairman, is useful to

ensure decision–making, the size of commissions, including chairman, can vary from one member (United Kingdom) to three (Orissa in India), five (FERC in the United States, Argentina, Mexico, New York, Pakistan) or seven members (Federal agency in Canada). On the basis of international experience, the regulator should not have more than seven members.

Terms of appointment can vary from five years (Argentina, Bolivia, United States) to six (California State Commission, New York) to seven (Canada, European Union). Most appointments are renewable for at least one additional term. To ensure continuity of decision–making, staggered terms of four to five years are often appropriate.

1.4.7

Staff skills and competencies

A regulatory body of high quality cannot be set up without the right resources, an

rectly trained staff. Commissioners and staff with the right qualifications and experience must be hired. Where all positions cannot be satisfactorily filled, training should be arranged for staff.

Commissioners' personal attributes should include the ability to consider multiple perspectives and resistance to improper influences and preoccupations. Training and experience in engineering, economics, finance, law or public a

In selecting staff, emphasis must be placed on skills as well as on personal integrity. Market–based salaries are desirable, and this may call for exceptional measures or incentives to recruit and retain the qualified professionals needed.

Staffing head count is important. Understaffing prevents proper attention to required functions. In the contrary overstaffing can dilute focus. Rather than attempt to recruit and maintain all expertise on a permanent basis, a regulatory agency can rely on expert consultants and fixed–term contracts, keeping the permanent commission staff as small as possible. Depending on

the size of the country and the resources available, the regulator could contract out or outsource activities such as detailed analytical work and compliance audits of regulated firms.

When selecting and evaluating staff for regulatory agencies, there is often a focus on specialist skills and knowledge, relating to the sector being regulated.

In the case of energy, specialist skills that might be targeted are, for example:

- Electricity systems,
- Natural gas systems,
- Energy economics,
- Energy contract negotiations, etc.

Training and experience in engineering, economics, finance, law or public administration are also useful. There is also a need to assemble staff that have overarching organizational management knowledge. These include knowledge and/or competency in areas, such as, personnel management, financial control and operational management. Without good general management abilities no regulatory body will operate effectively regardless as to the degree of specialized effectiveness of any organization at all levels of seniority. Soft skills relate to the unseen abilities of staff and managers, such as, their:

- personal motivation,
- ability to communicate well,
- ability to work in teams,
- level of basic education, and
- IT literacy.

These soft skills can have an enormous impact on the effectiveness of organizatio
these are taken into consideration when recruiting staff.

A shortage of skills can seriously impact on the ability of regulators to conduct their activities. Therefore, in most cases staff training is necessary to overcome this inability. Training may be best delivered as a set of short courses and seminars, which cover a range of regulatory knowledge areas. A structured cost effective training programme can be undertaken over a period of time. The focus should be on providing the knowledge which regulators need. Some of the areas where training is most likely to be required are:

• Funding a regulatory body,

• Understanding the nature of the utility market, such as, natural monopolies and

• Ensuring that any restructuring or consolidation of companies providing a utility service was compatible with effective competition,

• Financial analysis,

• Regulating overall price levels,

• Controlling pricing when users have no choice of supplier,

• Tariff setting,

• Information issues,

• Making good regulatory decisions,

• Reviews of and appeals against regulatory rules and decisions,

• Knowing how to communicate to the public,

• Negotiating techniques and strategies,

• Critically reviewing company plans to provide utility services.

1.5

Building a credible energy regulatory arrangement

While regulatory concerns make up only a small part of the investor's overall risk regulator by negotiating directly with the host government.

1.5.1

Transparency

The understanding of regulatory transparency is complicated. Transparency is often seen as a critical component of good regulation because it increases the legitimacy of regulators in the eyes of regulated operators, government officials and customers. Indeed, increasing transparency is sometimes presented as a key reason for setting up an independent regulatory agency, on the assumption that this allows more transparent regulation than or through a ministerial body. However, the degree of transparency in regulation is not always optimal.

Fostering transparency in regulation therefore remains a key challenge.

Transparency in government is increasingly demanded by private corporations an academic literature alike. Transparency can help to prevent political capture, reduce regulatory intervention risk and discourage corruption. In the utilities secto term, large–scale and sunk investment requirements,
transparency is particularly important to attract private sector investors and reassure customers.

There is little consensus on the definition of regulatory transparency. In essence, transparency allows the institution carrying out regulatory functions to operate independently (with respect to the tasks and functions over which it has discretion) whilst fostering the legitimacy of the regulatory process.

However, measures to improve transparency of the regulatory process cannot

be simply imported or transferred from one regulatory system to another.

Transparency requirements should instead take account of three main factors:

• the broader institutional and legal framework,

• the type of regulatory regimes, and

• the cost and affordability of transparency.

The importance of regulatory transparency as well as how this can be measured are provided below.

Why is regulatory transparency important? Transparency is important for independent operation while assuring legitimacy of the regulatory process. However, whether the emphasis is placed on transparency or not depends on the general institutional framework in a country. Information diss reaching all the stakeholders. Finally, the commercial confidentiality of the regulated bodies needs to be taken into account.

Transparency is also important because it is a unique part of attracting and retaining investment. It does this by reducing regulatory risks faced by investors. Many investors view transparency as a threshold to investment deci risks through greater transparency mean lower cost of capital and thus lower required rates of return. Transparency creates confidence in the commitment from the government to a defined set of policies both in the short–term and in the long–term.

Transparency facilitates better regulatory decisions taking account of all stakeholder interests and prevents corruption and regulatory capture.

Many regulatory documents are placed in the public domain, including decision statements. Regulatory documents are fairly comprehensive, and usually set out tariff review procedures, intended methodologies and consultation process requirements. This can be considered to be the

“bare minimum” of factors that should be set out in publicly available regulatory documents.

How can regulatory transparency be measured? The degree of regulatory transpar

These include:

(i) clarity of roles and objectives,

(ii) predictability,

(iii) transparency of decisions,

(iv) accountability,

(v) participation, and

(vi) access to information.

Many of these dimensions overlap with what is considered good regulatory gover costs and these must be recognized. The importance of well–defined appeal mechanisms must also be properly understood. The implementation of a re three partly–overlapping dimensions of the institutional framework, the regulatory regime and a number of trade–offs that will need to be made.

A number of ways to increase regulatory transparency are given below, although this is not an exhaustive list:

• Increasing regulatory transparency can be enhanced if the regulator circulates dı finalizing a regulatory decision or decision process,

• Where in–keeping with the limits of confidentiality, the publishing of regulatory contracts is a practical way to promote transparency,

• Encouragement of customer involvement can be very useful as an action to enhance transparency,

• Readily accessible language and terminology are also important to

enhance regulatory transparency,

• Clearly articulated procedures for licensing, including interaction with stake–holders and public consultation as part of this process,

• Active use of websites for disseminating information on regulatory decisions and regular press briefings.

A set of guidelines for regulatory transparency are listed below.

Clarity of roles: Formally codify regulated entities' functions in a licence and/or contract and objectives, define regulator's functions and duties in primary legislation or regulatory documents,

Predictability: Set out in regulatory documents the tariff review procedures and methods,

Transparency of decisions: Place major regulatory documents in the public domai in full or in a summary, the regulator's comments on points raised during the cons regulated entities and the public.

Participation: There should be compulsory or voluntary consultations on regulatory decisions or processes with regulated firms, other industry firms and consumers by means of public hearings, dissemination of draft reports for comment by stakeholders and focus groups, or meetings with representative groups.

Accountability: Set out in primary legislation the rights of contract or licence–

regulated entities or other stakeholders to formally challenge a regulator's decisic licence–regulated entities or other stakeholders' right to challenge the regulator's decisions by means of an appeal or a judicial review.

Open access to information: Publish an annual report (regulator and regulated ent secondary legislation, other regulatory documents, consultation papers,

regulatory decisions and information for consumers.

Transparency can be particularly challenging for regulators to promote when trying to reach small end–users and consumers, particularly because these often have very limited knowledge to information. A way to overcome this is to increase emphasis on regulates and third parties contributing to, and participating in, regulatory policy and rule–making. Potential benefits of this approach are:

• Improved information flows,

• Better transparency,

• Greater accountability.

However, there are disadvantages to this approach, as, for example, direct access transactions.

1.5.2 Communication strategy

Part of building a credible regulatory environment is the establishment of good communication channels with all stakeholder groups. This means that communica
discriminatory and not unduly
influence the regulator but provide useful information on stakeholder views.

The key stakeholders to communicate with are:

• The consumers,

• The utilities,

• Energy companies, and

• The government.

In many countries there is a lack of awareness on the role of an energy regulator. The information about the role and activities of the regulator is often not well disseminated and this sometimes leads to incorrect perceptions by end–users (customers) that the actions of a regulator are an attempt by government to restrict their energy use or deny them the right to energy, or manipulation on the part of utilities to make higher profits. End–users have to be informed of the benefit to them with regard to actions taken by a regulator, in particular in the case of tariff increases or energy efficiency programmes.

There are a number of ways to create good information flow to the public and raise awareness. Different options will be better suited to different countries.

Some examples are:

• Newspaper adverts and articles,

• Radio and TV programmes and interviews,

• Periodic email alerts,

• Production and distribution of booklets,

• Creation of “Energy Advice Centres” to operate at a local level.

There should be a clear procedure laid out for end–users, energy companies and utilities wishing to communicate with the regulator. There should be the possibility to communicate by telephone, email, via a website and not just by

letter and there should be a fixed time limit for response to enquiries. Clear and transparent procedures should be laid out for a number of situations, so that all communications are dealt with in an equitable manner and under a fixed time frame. For example the following communications should have clear procedures:

• Announcements by the regulator to the stakeholders,

• Simple communications, e.g., requests for information, answers to factual questions,

• Stakeholder consultations,

• Requests for clarifications,

• Complaints.

The role of the regulator as a communicator of changes in the energy and electricity sector and in government policy is important and should not be neglected. The regulator should either have a member of staff dedicated to this role or clearly assign communication activities to members of staff who may also have other responsibilities (i.e., include communication aspects in the staff job description).

1.5.3

Evaluating a regulation system

To facilitate the building of credible regulatory arrangements, the development of a regulatory scorecard might be considered, focused primarily on the robustnes making. A regulatory scorecard could include:

• Extent to which regulatory decisions are published,

• Speed at which the regulator makes decisions,

• Ability (and willingness) of the regulator to procure external independent advic

• Quality of the Chief Executive of the regulatory agency,

• Rate of staff turnover, particularly of the Chief Executive and key managers anc

A scorecard has the advantage of enabling comparison between sectors and/or countries. Also, it could help measure improvements. However, which indicators are chosen and how they are measured must be considered carefully.

For meaningful comparisons to be possible, consistent, good quality data must be collected.

Fundamentals of Energy Regulation

Chapter 2

Energy Markets

Energy markets are a collection of commodities that are quite different in nature. It is, therefore, helpful to break them into three groups:
(a) Fuels, such as, oil, gas, coal, including their derivatives and byproducts,
(b) Electricity,

(c) Weather, emissions, pulp and paper, and forced outage insurance.

This classification roughly corresponds to the historical pace at which these markets have been opened.

Fuel markets, and especially oil and gas markets, opened to competition in the 1980s at the wholesale level. Electricity markets followed in some countries in the early and mid–1990s. Finally, the late 1990s saw the rapidly increasing pace of trading in new types of commodities related to electricity such as weather and emissions.

The term fuels might suggest an electricity–centric perspective. However, oil and gas are also used for direct consumption, and, in fact, their demand as heating fuels is driving their price formation.

2.1

Fuels and electricity as physical commodities
As with any physical commodity that has independent value apart from its investment value, the markets involve three sets of activities:

• production,

• distribution, and

• consumption.

These activities give rise to several types of services. For example, distribution in the gathering system, to a processing facility, and then on through the main line to receipt points, with possible stops along the way at storage facilities for balancing purposes. Before deregulation, this complex activity was often managed by one entity that had control over a significant portion of the local dist monopoly power and resulted in heavy regulation that both controlled and sustained the problem.

Concerns about the enormous inefficiency of this situation led to the on–set of deregulation. The process has entailed two things:

• an (often forced) unbundling of the services, and

• the creation of markets to mediate the provision of the services.

The extent of deregulation varies with commodities and locations. The degree to which the interaction among the components of the value chain is handled through markets or by public utilities, also, varies considerably. One point worth mentioning is that the organizational details of the physical markets h and derivative markets. Given the complexity of some of those markets[1], underst between the different markets presents a challenge that should not be underestim

2.2 Oil and gas markets

Although oil and natural gas are put together under the heading of fuels, their respective markets operate quite differently. The market prices had been effectively fixed until 1985, when the OPEC pricing regime collapsed. This led to the creation of active forward and spot markets. The crude oil market

is the largest commodity market in the world. The most significant trading
1A perfect example is the electricity market that trades several cash products.

hubs are New York, London, and Singapore. These markets trade crude oil, as well as, refined products such as gasoline and heating oil.

2.2.1 Crude oil

Crude oil comes in a wide variety of grades, determined by its gravity and sulfur content. The world benchmark crude oil is the Brent crude pumped from the North Sea oil wells. Estimates indicate that up to two–thirds of the world supply is priced with reference to this benchmark. In the United States the benchmark is the West Texas Intermediate (WTI) crude oil.

The forward markets in the United States are conducted on the New York Mercantile Exchange (NYMEX). The NYMEX crude price most often quoted is the price of light, sweet crude oil. Sweet refers not to its flavor, but to its sulfur content. Oil with sulfur content below 0.5% is referred to as sweet, while oil with higher sulfur content is called sour. The spot markets tend to be rather thin, with the bulk of the transactions concentrated in the financial and physical forward contracts.

2.2.2 Oil refined products

Crude oil needs to be processed (refined) in order to yield products that can be directly consumed. The most popular refined product is obviously gasoline.

Heating oil and fuel oil are often used by utilities. Kerosene[2] powers the airline industry. Heating oil and fuel oil of various grades have extensive forward markets, both exchange–based, such as, NYMEX. The liquidity in

those markets varies substantially.

2.2.3

Natural gas

The gas markets were steadily opened to competition during the 1980s and early 1990s. Regarding demand characteristics of natural gas, in most of the countries the heaviest residential consumption is during winter months for home heating, reflected in the relatively high winter prices and low summer p summer and winter might be affected in the future by the growing stock of
2Jet fuel.

gas–
powered electrical generation. Since the bulk of seasonal variation in electricity c conditioning, electricity consumption is highest during summer. This could lead to a relative shift in natural gas demand towards the summer months.

There are five categories of market participants:

- Gas producers,
- Pipeline companies,
- Local delivery companies,
- Consumers,
- Marketers.

The first four market players have well–defined roles along the value chain of the industry. Marketers serve as intermediaries, managing the interactions of the other parties. Transactions in the natural gas physical markets are conducte

• Delivery and receipt of natural gas at a given location,

• Transportation of natural gas between two different locations.

Depending on their position in the pipeline system, these locations experience dif

Natural gas transportation transactions have similar contractual provisions. There
Firm transportation service: The highest priority service.

Interruptible transportation contract: Under this contract a pipeline has an option to interrupt the service on short notice without a penalty. The interruption generally occurs in peak–load seasons as a result of demands from firm service customers. Also, referred to as best efforts.

Although most of the firm capacity is subscribed, there is an active secondary ma
pipeline sells some of the capacity, the transaction is referred to as capacity release.

2.3

Power markets

The design of efficiently functioning electricity markets has proven to be a challenging undertaking. The physical characteristics of the commodity are quite unlike those in the fuel markets. One of the crucial features of electricity markets (and one that differentiates it from other commodity markets) is the need for real–
time balancing of locational supply and demand. This requirement flows from the

Since electricity cannot be stored, instantaneous supply and demand must always be in balance, otherwise the integrity of the whole system might be compromised.

This peculiar feature of electricity markets introduces the need for an additional s

and reserve resources. Therefore, the supply of electricity involves three types of activities:

• Generation,

• Transmission, and

• Ancillary services (balancing).

Around the world, there are considerable differences in the extent to which these activities are mediated through markets and/or public utilities. The common feature of virtually all solutions is the presence of an independent system operator, which is responsible for maintaining the system. The services can then be managed by either a highly centralized market under the control of the independent system operator, or through a sequence of bilateral markets, with the independent system operator only playing a limited role as a sole buyer of some of the services.

The solutions include a system where the independent system operator manages provision, contracting, and infrastructure for all the activities of the electricity markets (generation, transmission, and balancing). In other markets, th of generation (the energy market) while transmission is left to bilateral markets w the buyer of the final product. Finally, some markets are purely bilateral, with only a symbolic presence of the system operator.

2.3.1 Primary market structures

The cash market takes on two contracting structures, namely, pools and bilateral r

Pools: The main characteristic of the pool market is the formal establishment of tl transactions clear. Examples include the Nordic Power Exchange (Nord Pool), New England Power Pool (NEPOOL), New York Intrastate Access Settlen

Bilateral Markets: All transactions are entered into by two parties and are independent of any other transactions in the market. Examples include the Electric Reliability Council of Texas (ERCOT), the East Central Area Reliability Council (ECAR), and the Southeastern Electric Reliability Coun

The products offered by pool markets vary widely from market to market.

Several markets trade main energy cash products as well as the ancillary services. or multiple settlement system.

Energy cash markets

The different energy cash markets are as follows: Day–
ahead market: This market transacts for generation of energy the next day. Every hour is transacted separately. In some markets, the structure of the bid is very simple; in other markets startup and no-load bids can also be transacted.

Day–of or intra–
day market: This market transacts for generation of energy for the rest of the day.

Hour–ahead market: This market transacts for generation of energy for the next hour. This is a reconciliation market that clears any deviations from the predicted schedules entered in the earlier markets.

A market that has more than one cash market is referred to as multi–settlement market.

Energy forward markets

Energy forward markets are markets in which the parties contract for the delivery of energy in the future. The future in question can be near (e.g., balance–of–the–week and balance–of the–month products) or quite far (e.g., monthly forward contracts that cover periods months or even years into the

future). The forward markets take on three basic forms: Bilateral or broker–based (over–the–counter) market: The trading involves either direct contact between two parties or a broker.

Market–based market: The trading is centered around a market maker who posts two-sided (for buying and selling) quotes, stands behind every transaction, and can carry inventory.

Exchange–based market: The trading centers around a central exchange that matches up buyers and sellers and guarantees the performance of the transaction without taking an outright position and carrying inventory.

2.3.2 Types of power trading

On the surface, electricity seems to fit the definition of an almost ideal commodity power sold in the morning is completely different from power sold at the same location in the evening. For this reason there are many varieties of products traded in the power markets, making the study of these markets even more difficult. Frequently encountered hourly power products include: On–peak power: Power during the high–demand periods.

Off–peak power: Power during the low–demand periods (complementary to on–peak).

Other products include, 2–, 4–, 8–, or 16–hour blocks of power, next–day power, balance–of–the–week power, next–week power, balance–of–the–month power, and next–month power.

2.3.3 Ancillary services and ancillary services markets

In electricity markets, instantaneous supply and demand must always be in balance, otherwise the integrity of the whole system might be compromised.

This creates the need to hold reserves to balance instantaneous variations in load. The way this need is handled depends on the market design. In some electricity markets the need is satisfied by requiring generators to withhold part of their generation capacity of committed units for the so–called spinning reserve. In practice this means that a generation unit does not ramp up to full capacity unless called upon by the system operator to help balance the system in a contingency.

Another solution is to create a market that supplies those services. A number of pool markets use this method. In the market–based scheme, the generators have the choice of committing their available capacity either to the energy market or to one of the ancillary services markets. In some regions, ancillary services markets are composed of as many as seven products. A typical list includes:

Spinning reserves: Resources synchronized to the system that are available immediately and that can be brought to full capacity within ten minutes.

Non–spinning reserves: Resources not synchronized to the system that are available immediately and can be brought to full capacity within ten minutes.

Operating reserve: The resources that can be brought to full capacity within 30 minutes.

Energy imbalance: Resources needed for correcting supply/demand imbalances.

Regulation: Reactive energy to maintain the phase angle of the system.

Reactive power supply: Services to maintain voltage of transmission lines.

As such, it is locationally specific.

2.3.4

Installed capacity markets

In some markets, the long–term reliability of the system is managed through

capacity markets. These arose from the need for all load–serving entities to

show the availability of physical supply from which the load will be served.

This type of market assures a long–term reliability, and short–term reliability is handled through the ancillary services markets. Installed capacity markets are usually specified as excess to the peak load. It differs from market to market, but it can be as high as 110% of the peak load.

In a market with capacity requirements, the additional revenues for the generators will induce more entry and lead to higher reserve margins, defined as the difference between the maximum system capacity and the peak system load. This has consequences not only for reliability but also for the behavior of energy prices themselves. When we analyze the economics of power markets more extensively, we will show how reserve margins have a substantial impact on the probability and amplitude of price spikes. Price spikes are useful in two ways:

- On the demand side, they help to signal shortages and encourage customers to r

- On the supply side, they signal shortages and help bring in more supply/additio

On the other hand, extreme price spikes can be very disruptive. Many market designs strive to retain the features mentioned above without having actual spikes. The capacity market should have the effect of encouraging entry (supply side), thus preventing spikes while maintaining sufficient reserve margin side signalling cannot be achieved by this mechanism.

A moot point since there is currently almost no disaggregated demand–side metering. Consequently, no price signals can be sent to the customer, no matter w bidding rules, and coverage periods differ from market to market.

2.4 The economics of electricity markets

Understanding the basics of economics and technologies of electricity markets can help understand the behavior of energy prices in general.

On the supply side of the business, the following technologies currently dominate electricity generation:

• Steam turbine using nuclear fuel,

• Steam turbine using coal,

• Steam turbine using oil,

• Combined cycle using natural gas,

• Open cycle gas turbine using natural gas,

• Hydropower,

• Renewable energy sources for power generation.

Different countries have different mixes of technologies. The most prevalent ones are coal, nuclear and natural gas based technologies. The last category is quickly gaining in importance, since almost all substantial new generation being built is based on natural gas. The importance of natural gas lies in its relative environmental advantages, high efficiency and low cost. In certain seasons, hydrological resources can be of significant importance in various countries.

The characteristics that determine cost of generation are listed below:
Capacity: Maximum power output of the unit expressed in MW.

Heat rate: A measure of efficiency of the unit, that is, its ability to convert fuel energy content, expressed in kJ, into electrical energy, expressed in KWh.

Variable O&M costs: Variable operational and maintenance costs, per unit

of generation.

Min/max generation level: Maximum generation level is the unit’s installed capacity. Minimum generation level is the technically feasible minimum level. For steam units, the min levels are around 30% to 50% of total capacity. For some gas turbines they can be as high as 80%. This characteristic ha its optionality.

Scheduled outages: Planned downtime for maintenance. Units typically require 2 to 4 weeks of downtime annually.

Forced outages: Unplanned downtime caused by a technical failure of the unit. Expressed as equivalent forced outage rate, which is defined as the number of outage hours in a measurement period divided by the number of available hours in that period. Outage rates depend on the unit’s technology, its age, and its operating conditions. The outage rate can run from 3% to more than 20% for some units. In general, the timing of individual outage events can be influenced to some degree by operating decisions, and individual outages can be delayed by certain actions. However, this can entail substantial cost down the road or a higher outage rate later. Outage rates have an impact on the value of the plant, because they limit the total amount of energy available from a unit. More importantly, outage rates can have a substantial impact on the risk profile of a unit’s cash flow.

Ramp rates: The rate at which the generation level can be changed, expressed in M ramping units have rates of around
5MW/min. This characteristic has a major impact on the flexibility of a plant, and consequently on its ability to capture hourly and other short–term optionality.

Startup/shutdown costs: The costs of starting up or shutting down a unit can be of three types: (a) fixed cost per event, (b) fuel consumed in a start–up and (c) electricity consumed in a start–up. For large baseload

units, fixed start–up costs can run into tens of thousands, and must be differentiated between various start–ups. Depending on the state of the unit, a start–up can be cold, warm, or hot. This classification refers to the state of the boiler in steam–powered units. The colder the boiler is, the more expensive it is to heat it up again. The cost of start–up increases accordingly. The size of these costs has a substantial impact on the value of flexibility associated with the unit. It tends to have a disproportionately high impact on the risk profile of the unit cash flow, and it can also tend to induce significant hedging costs.

Min/max runtime, min/max offline time: For technical reasons, various restrictions on the length of runtime and/or offline time can be present.

These restrictions can significantly affect a unit's flexibility and thus its ability to exploit optionality.

Although a number of technologies are used in generating electricity, the

technology itself involved usually is not of much interest. The main technical characteristics that impact valuation and hedging, such as start–up costs, ramp rates, heat curves, fuels used, and emission rates will be sufficient to characterize the financial impact. Using these categories we can distinguish three main families of thermal generating units: (a) Baseload,

(b) Cycling,

(c) Peaking.

The technology used in different classes of generation units can be based on a variety of principles. Some power plants have multi–fuel capabilities, that is, the ability to switch between different fuels, depending on operational or cost considerations. In some cases, the switch can be made without delay and at a low cost, but in others it might involve a shutdown and all the consequent costs.

Operational costs of units are affected by the following items:

• Fuel costs,

• Variable O&M,

• Emissions costs/emissions restrictions (they can have cumulative instead of marginal character),

• Transmission costs (depending on the market design).

Knowing the unit characteristics and the cost items above, the marginal cost of generation for all the units in a given region can be calculated. By stacking the units in merit order, that is, from the lowest to the highest cost, we can form what we call a supply stack. The marginal cost of a unit depends not only on current fuel costs, but also on the previous states of the unit. The operating characteristics mentioned above (startup costs and min runtime) can create dependencies between different unit states at different points of time. This obviously suggests that the marginal cost will be path–dependent.

If we ignore the above subtleties, we can form the supply stack by considering only the marginal fuel costs (and variable O&M). The supply stack is then a potentially multidimensional surface that shows us the marginal fuel cost for the different system generation levels and fuel prices.

In almost all countries, the marginal fuel (the fuel that sets the price most often) tends to be natural gas. The marginal fuel cost stack surface (generation stack) maybe not necessarily equivalent to the actual bid stack submitted for optimization in different pools. For certain regions we have at our disposal the actual bid stack used. Consequently we can compare the marginal fuel stack with the actual bid stack used in determining system price. The importance of this exercise lies in the fact that the structure of the stack helps us understand the behavior of power and fuel prices. For that to be a viable option, we must reasonably expect that the structure of the marginal fuel stack is close to the

actual bid stack.

The differences in the fuel and bid stack are due to several factors. The actual marginal costs of the different generators can be influenced by a number of physical constraints, and in some situations, this might make fuel cost an insufficient proxy for the actual marginal cost of generation. Furthermore, the differences can be induced by strategic behavior by the bidders.

Depending on the structure of the market, the dispatch of a generation unit can be significantly different. In pool markets, where we have one market clearing price (at least for energy), the optimization of dispatch is greatly simplified. The optimization of generation assets is independent of any load obligation, storage facilities, and any financial (or even physical) contractual arrangements. It follows that the operation of a unit is by and large not affected by any hedges the generator might hold. This is strictly true only for risk–neutral operators.

For certain market designs, hedging strategies can influence operational decisions through the impact of risk–
reduction on the optimal dispatch decisions. For example, if an operator enters in at least the start–up and no–load (minimum generation level) costs will be recovered the operator will be willing to start up the unit more frequently.

This consideration, however, depends on the specifics of the pool design.

In bilateral markets, dispatch involves optimizing generation, given contractual lo power or buying needed resources in the cash market. The problem in purely bilateral markets is that the price discovery process can be quite inefficient.

Fundamentals of Energy Regulation

Chapter 3

Capacity Markets

There is a difference between energy and capacity. Power plants are compensated system in different ways. More specifically, a power plant generates electricity th happens in the energy market. In these markets electricity is like any other commodity, bought wholesale and resold to consumers at retail prices. However, needs to be delivered. This is important, since power plants are expensive and

take a long time to build. Adding the additional risk that they may not even be used can obviously discourage investment. Hopefully, these markets create long–term price signals for all resources.

There is an increasing concern by policy makers in Europe and elsewhere that liberalized wholesale markets for electricity do not provide the incentives to build adequate generation capacity. This concern is justified. Current electricity markets, with their demand–side flaws cannot determine efficient prices that would minimize total costs, including blackout costs. The central problem is the failure of wholesale markets to generate prices that reflect the opportunity cost that consumers place on electricity consumption in times when all available capacity is fully utilized. Yet these prices are crucial for the decision to invest, or not, in generation capacity.

The basic idea is that power plants receive compensation for capacity, or the power that they will provide at some point in the future. The way these markets are run is that there is an auction every year that has a delivery date, e.g., three years away. This auction is called the Base Residual Auction. Then,

there are smaller balancing auctions every year leading up to the delivery date where bidders can buy or sell their commitments. These are called Incremental Auctions, and occur just in case a power plant cannot meet its commitment, and needs to purchase replacement capacity from another power plant. In capacity market auctions, there is no functional difference between a MW of power from a power plant and a MW of reduced power from efficiency or demand response. So when referring to power plants demand–side resources can also bid into the auction.

Capacity markets are important. They are the firing line for the electricity system of the future, because they direct and encourage investments in different k
resources like efficiency.

3.1 How a capacity market works

Every resource bids into the auction at its total cost of operation. Since power plants depreciate over time, this bid can sometimes be very low if a plant has been around for a long time. This makes sense, since the capital investments in the plant have been paid off and the total cost of operations is mostly employees and fuel. New plants' total cost of operation is higher at first, since it includes capital costs plus operational costs. This means that what price a power plant bids into the market can vary quite dramatically. A 30 year old nuclear plant could actually bid in very low and a wind turbine that has zero fuel costs could have a much higher bid.

So what happens is that the grid operator holds an auction based on projections fc bit extra as a buffer (called a capacity reserve margin). Pretend that the grid operator had to meet 550MW of peak demand. The grid operator will then hold an auction to try to get the 550MW of demand met at the lowest cost to consumers. Thus, every resource bids into the auction in at its total cost of operation as illustrated in Figure 3.1 where cost bids are presented from lowest to highest, and the doted line represents the point where enough capacity has been acquired to meet demand.

For example the cheapest resource is one wind turbine bidding in 50MW

of capacity at 30e/MW. Just because that particular wind turbine bid in 30e/MW, that does not mean that the turbine receives 30e/MW. All it means

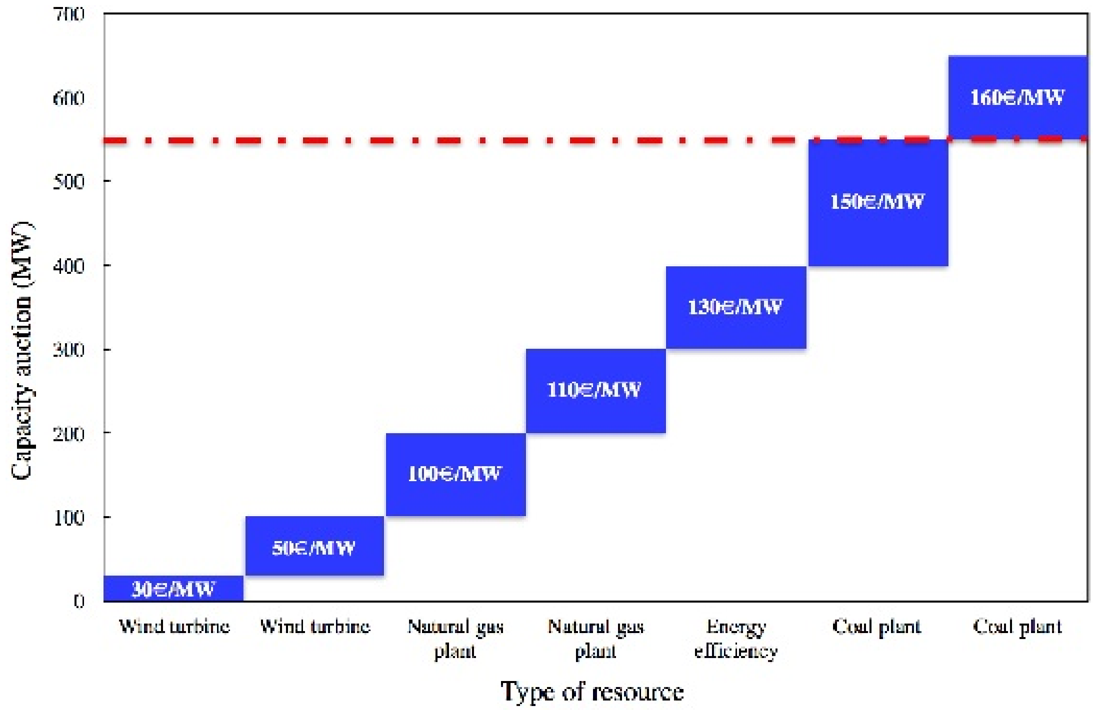


Figure 3.1: How a capacity auction works.

is that the wind turbine is now committed to have 50MW of power available in 3 years from now. Looking further up the stack, another wind turbine bids in 50MW at 50e/MW. Even higher up the stack, energy efficiency bid into the auction at 130e/MW, and a coal plant bid in at 150e/MW. So what compensation do they receive? In this example, all of the resources, including the wind turbine at the bottom, receive 150e/MW. This is called the clearing price, and it is set by the most expensive unit needed to meet demand. In this case, that is the coal plant. This is important to understanding the dynamics between different resources in the market.

Furthermore, energy efficiency actually displaced a coal plant whose total cost of operation was 160e/MW. If energy efficiency (or demand response) had not bid into the market, then demand would have been 100MW higher and that coal plant would have to be called on to meet demand. Then the clearing price would have been 160e/MW.

Because Base Residual Auction is followed by few Incremental Auctions, there can actually be some weird exchanges. Referring to Figure 3.1, imagine that the coal plant receives the 150e/MW capacity payment but then goes

offline due to equipment malfunction. Suddenly, they are on the hook for 150MW of capacity that they cannot provide. So, in the next Incremental Auction they sell their 150MW commitment. If the clearing price in the Incremer made 20e/MW. This is because the coal plant received 150e/MW for something that someone else is now going to do for them for only 130e/MW.

Finally, in capacity markets, lower cost resources can have the effect of suppressing prices for all of the resources since they ensure that demand can be met at a lower cost. For utilities who own lots of expensive generation, this is bad for business. For a company who owns lower cost resources, it is good.

Consumers always benefit from lower prices.

3.2 The adequacy problem

Suppose electricity markets did not suffer from demand–
side flaws. In particular, suppose demand is sufficiently responsive to prices, sucl electricity market always clears. Then, the market would be perfectly reliable.

If supply is scarce, the price would rise until there is enough voluntary load reduction to absorb the scarcity. Consumers would never suffer involuntary rationing. However, current electricity markets do not converge to guarantee market clearing.

The main problem is a lack of real time meters and billing and other equipment to allow consumers to see and respond to real time prices, resulting in low demand flexibility. Because storage of electricity is costly, the supply side is also inelastic as capacity becomes scarce[1]. As a result, there is a possibility of non–price rationing of demand in the form of a rolling blackout,

as illustrated by Figure 3.2. During a rolling blackout of electricity, although all available generators produce as much electricity as they can, irrespective of the price level, not all demand can be served.

Current electricity markets do not prevent the possibility of blackouts, and the present discussion assumes that this will continue to be the case2. In fact,

1Capacity includes both generation and equivalent demand response, but for conv this is referred simply to generation.

2Capacity markets generally encourage the development of demand-side resources, but even with this encouragement it appears that adequacy concerns will continue to significant role in electricity markets for quite some time to come.

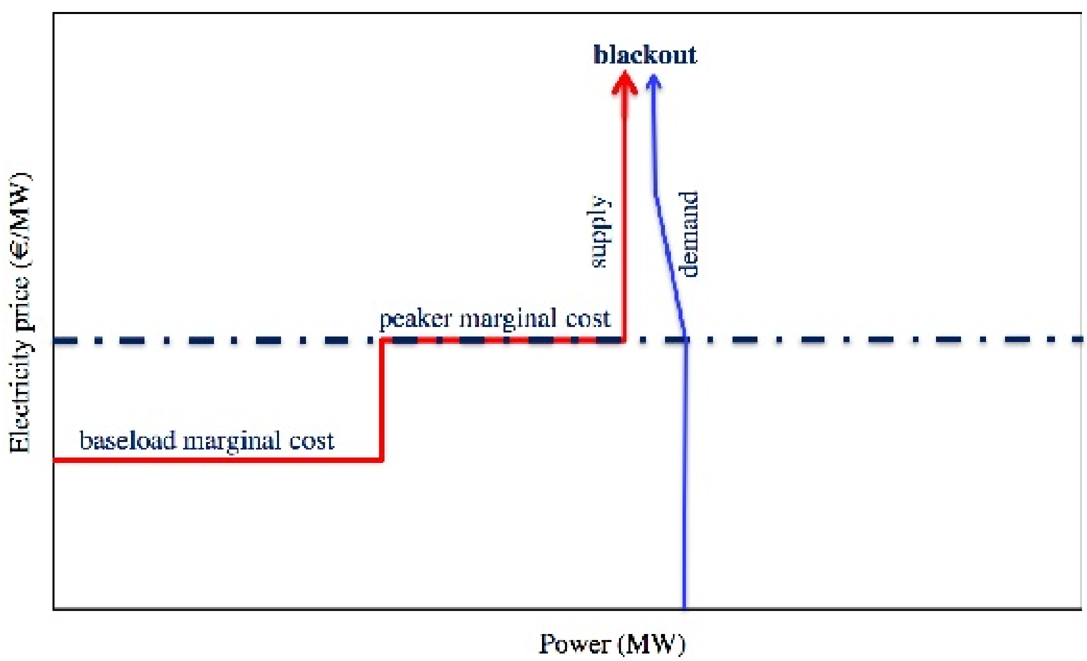


Figure 3.2: Illustration of blackout (when supply cannot equal demand).

given the demand–side flaws, fully eliminating blackouts due to insufficient generation is unlikely to be optimal.

The Value of Lost Load (VoLL), is defined as the amount that consumers would pay to avoid having supply of power interrupted during the blackout.

Suppose that the:

(a) average annual duration of blackouts is five hours per year and that VoLL = 20000e/MWh

(b) rental cost of reliable capacity (RCC) is 80000e/MW–year.

If one MW of capacity is added, it will run five hours per year on average and reduce the cost of blackouts by 100000e/year. That is more than the cost of capacity so new capacity should be built up to the point where the duration of blackouts falls to 4 hours per year and the marginal cost of capacity equals the marginal reduction in the cost of lost load. That is, the optimal expected duration of blackouts is:

RCC

optimal expected duration of blackouts =

.

(3.1)

V oLL

As long as the rental cost of reliable capacity is positive, efficiency requires that blackouts occur with positive probability. However, a key insight is that electricity markets cannot optimize blackouts. To see why, observe that the economics of competitive markets assumes that the price will always clear the market. That is, competitive economics starts by assuming that there is no adequacy problem and concludes that in market equilibrium production costs are guaranteed to be minimized. However, competitive markets cannot optimize b

generation capacity built to avoid them, and the incentive to build generation to avoid blackouts depends on the price being paid during blackouts. Yet there exists no competitive market price during blackouts as illustrated in Figure

3.2. The price that is being paid to generators during blackouts must be set by administrative rules.

The failure of markets to optimize blackouts goes beyond the case of rolling blackouts. For instance, when capacity gets scarce there is, also, an increased probability of network collapse. But a network collapse implies a market collapse, because, as electricity cannot be delivered during a system collapse, consumers are not willing to pay a price during the collapse. As a result, market mechanisms cannot capture the cost of catastrophic blackouts and thus not optimize their occurrence.

Furthermore, the challenge to find prices during blackouts is not related to the well–known literature on peak load and scarcity pricing, and investment incentives in electricity markets. Scarcity pricing relies on market clearing prices. The basic idea is that, if all available generation capacity is fully utilized, there may be excess demand at a spot price that is equal to the marginal production cost of the last unit provided by the physically available generating capacity. Because supply cannot do anymore to balance supply and demand in such a scarcity event, the demand side is then required to bid prices up until the market clears.

At the resulting scarcity prices, all generators that are supplying energy in such scarcity events earn scarcity rents, which in turn are needed to cover the fixed capital costs. This mechanism is essential to investment incentives in all energy markets. However, it cannot help in optimizing blackouts or in finding efficient prices when there is a possibility that no market clearing price exists due to demand-side flaws.

Peak load and scarcity pricing require high prices and electricity markets often impose price caps. This combination leads to the view that the root of

the adequacy problem is price suppression by the energy regulator, and that discontinuing that price suppression can solve the adequacy problem. But this is not the case. In fact too high a price cap can result in too much capacity.

The following example of how this can happen may help explain why the adequacy problem is ultimately the result of demand–side market failures and not the result of regulatory price suppression.

Suppose a blackout occurs when a large generator has been out of service for a week and the weather becomes hot and consumers gradually turn on their air conditioners. Consumers value lost load at VoLL = 10000e/MWh.

There is also demand elasticity with demand dropping smoothly between 1000e/MWh and 20000e/MWh, but not dropping by much. As demand rises during the hot afternoon, it would eventually exceed total supply by a tiny amount if the price stayed at the variable cost of a peaker, assumed to be 200e/MWh. But instead, the price at which supply equals demand will jump to just over 1000e/MWh and that will decrease demand slightly. So far, the market is optimal and generators are earning normal scarcity rents, as discussed a regulator does not intervene, the price will continue on up to 20000e/MWh.

This is not optimal because non–elastic consumers (almost all of them) are paying twice what power is worth to them. When they overpay, as in this example, it sends a signal for the market to build too much capacity.

Again, there is no way for the market to escape this dilemma on its own. Supply and demand intersect at 20000e/MWh and there is nothing special that any market participant can observe about the price VoLL at 10000e/MWh. So, the market sets the wrong price. But as soon as demand increa

At that time, no price will be determined by the market. The only result that can logically be predicted is that the price might stay at its most recently determined level, 20000e/MWh. But this is still twice too high.

More importantly, the value of 20000e/MWh set by some demand–elastic customer is not related to the average value of lost load among inelastic customer that just one unusual customer who is watching the price and buying wholesale has an extremely high value for giving up his last MW of power should not be relevant to determining the value of reliability for the majority of customers.

This brings us to the fundamental purpose of a capacity market, which is to provide the amount of capacity that optimizes the duration of blackouts. This

problem is known as the adequacy problem. The heart of the adequacy problem lies at resolving the trade–off between more capacity and more blackouts. This definition of the adequacy problem is convenient for at least two reasons:
First, almost all observers agree that current markets do have an adequacy problem according to this definition, and they agree that this is the problem that capacity markets attempt to solve, and
Second, a market with an adequacy problem so defined cannot satisfy all the assumptions of perfect competition.

3.3 Basic approaches to solving the adequacy problem

During rolling blackouts, essentially every generator is running, so all are paid the same high scarcity price. Typically, the price is capped too low. That means there is missing money, which implies too low a low level of investment in capacity. One key observation about missing money is that, since it is missing from scarcity hours, every generator is missing essentially the same amount of money per MW of capacity. There are two basic ways to restore the missing money in proportion to MW of capacity[3]:

• raise scarcity prices paid during blackouts (price–based approach), and

• pay every supplier of capacity the same amount per MW of capacity (quantity–based approach)

There is also a third, less commonly proposed approach, such as, to raise the requirement of capacity reserve margin, that is generators that are paid to standby and be prepared to supply more energy on short notice.

3.3.1

Price–based approach: energy–only market

The price–based approach uses what is often called an energy–only market.

This is a bit of a misnomer because such markets nearly always purchase some form of operating reserve capacity, and so include capacity–based instruments.

However, an energy–only market can be defined as the market that attempts
3In order to result in incentives for building the correct mix of generation technol

to solve the adequacy problem by setting a high price cap, which is the price paid during a blackout.

Normal market operation would dictate that the price should increase whenever demand exceeds supply. In a normal market, this will clear the market. But during a blackout, this would result in the price rising without limit s that causes the problem. It would also create significant opportunities for supplie is capped. If the regulator manages to set this cap at VoLL, the market will achieve the second–best outcome, known with slight exaggeration as optimal[4].

The market responds to VoLL by building additional capacity up to the point where a MW of capacity costs just as much as it earns from being paid VoLL during blackouts. So investment stops when the carrying cost of the last MW of capacity equals VoLL times the expected duration of blackout (in hours). But this is exactly the value of serving the load that would have gone unserved without that MW of generation. So at this point the cost of capacity equals the value of capacity to consumers, and beyond this point, consumer value per MW of capacity can only decline as the system becomes more reliable.

Hence, the VoLL pricing rule causes the market to build the second–best, optimal amount of capacity. This solves the adequacy problem. The energy–

only approach works because the market will build generators up to the point where an extra MW of generation makes revenues that exactly equal its costs

and at that point, equation 3.1 for optimal capacity holds true.

3.3.2

Quantity–based approach: capacity market

A capacity market approach requires that the regulator calculate $C*$, the level of capacity that results in the optimal duration of blackouts. This is a difficult and complex calculation. In reality both the determination of VoLL and the optimal duration of blackouts will likely remain a highly politicized process.

There is no objective way to estimate VoLL accurately, and whoever will be held responsible when blackouts occur will want and will usually obtain

4This is not optimal because VoLL reflects only the average opportunity cost that be forced to buy more reliability than they want and others less, but this is the bes can be done given physical limitations.

influence over the selected values.

Even with a quantity–based approach, the energy regulator will still need to set an energy price during blackouts, since the market cannot. However, this price will mainly serve to induce efficient behavior by existing plants and, unlike in an energy–only market, it will have no effect on the level of installed capacity. For example, assume the regulator sets a low price of, perhaps, PCAP = 1000e/MWh. This will be too low to induce an optimal capacity level of $C*$. To illustrate the fundamental difference of the quantity–based approach, first consider the capacity–market design that is most similar to the price–based approach.

In this design the capacity market is used to top–up the energy price to the level that induces $C*$. The regulator holds an auction for $C*$MW of capacity and allows new and existing capacity to bid a scarcity price PS, a price during blackouts, that would induce generators to remain in or to enter the market.

The lowest price, $P*$

S , that would be accepted by at least $C*$ of capacity would become the market’s new price cap. Then during scarcity hours, the capacity market would pay all generators that sold capacity, $P*$

$S - PCAP$, on top of the

energy- market payment of $PCAP$.

In effect, the auction discovers the value of the price cap that would correspond t solves the adequacy problem, and it avoids market coordination problems that occur when the market builds capacity in response to energy prices instead of a capacity auction. The auction coordinates the investors decisions to build, so they neither under–nor over–build. This demonstrates that a capacity market can act just like an energy–only market except for giving the regulator control over capacity. In particular, this provides exactly the same efficient real–time signals to build generators for both adequacy and security blackouts as does an energy–only market.

The reverse approach to designing a capacity market is equally simple.

Instead of capacity suppliers bidding for a higher scarcity price, PS, could bid for a capacity payment, $CPAY$. The advantage of this approach is that it does not increase risk and market power the way increasing the peak energy prices does. For the energy regulator, the price and quantity approaches differ, because the energy regulator determines VoLL in one and determines $C*$ in the other. Since these parameters control the capacity level and the duration of blackout, these two approaches are equally regulatory in nature. With the quantity approach, $C*$ can be determined either from a target duration of

blackouts, or it can be derived from VoLL. But even if derived from VoLL, the first step is to estimate a duration of blackouts from equation 3.1. Then, since blackout probabilities depend on the amount of installed capacity, C, it is possible to back out the value $C*$ that is the level of C that causes the desired

duration of blackouts. The calculation of blackout probabilities is a difficult task, but one that engineers have decades of experience with since regulated utilities use essentially the same approach to decide how much capacity to build.

Traditionally, and often with capacity markets, a target duration such as one day in ten years is used. One day is sometimes taken to mean 24

hours of blackouts and sometimes taken to mean one event of, perhaps, three hours. That discrepancy gives an indication of the arbitrariness of the target.

However, differences in the cost of electricity under those two standards are actually quite small, perhaps less than one percent, because spare peaking capacity is relatively cheap to build or keep online and because it requires essentially no fuel and few additional power lines.

In summary, the choice between the two basic approaches, price and quantity, is r

And both the quantity and price approach can solve the adequacy problem.

So the choice between the two depends on other factors, such as risk, market power, and the coordination of investments in capacity.

3.4

Alternative approaches to address the adequacy problem

3.4.1

Demand elasticity

There are more ways to address the adequacy problem. For instance, the adequacy problem could be eliminated by increasing demand elasticity to the point where the energy price never exceeds the value of energy to the average customer. In such a case, load could fully protect itself against blackouts, and mitigate market power in times of scarcity through increased demand response.

While circumstances could change, for instance, with the prevalence of smart grids, smart metering, and real–time pricing, as long as demand remains rather inflexible it cannot fully mitigate adequacy problems at scarcity events.

Moreover, increased demand responsiveness may not fully eliminate missing

money, risk and market power problems associated with scarcity events. So, even as the market moves towards an ideal environment, a capacity market could still be beneficial.

3.4.2 Operating reserves

Another approach uses a low price cap and solves the adequacy problem by buying operating reserves. Capacity bids in reserve power markets reflect short– or medium–term opportunity costs for withholding capacity from the spot market, plus short– or medium–term fixed costs, minus expected profits from actually being called to deliver rese not related to the investment costs of new capacity, thus cannot efficiently incentivize new entry, and so cannot address the capacity adequacy problem.

Power reserve markets can only indirectly incentivize investments by influencing capacity from the wholesale market, increasing the wholesale price and thus creating incentives for new investment. However, it seems unlikely that creating s efficient way of solving the adequacy problem. Holding back capacity from the wholesale market leads to an inefficient dispatch, and can bias the long–

term technology–mix. Also, it seems difficult to compute reserve requirements that would eventually incentivize the efficient amount of total capacity.

3.4.3 Strategic reserves

Another option which has been often put forward to address the adequacy problem is sometimes called a strategic reserve. This can take many forms. In the simplest version, energy regulators subsidize generators in order to induce their construction or to keep them in the market. One obvious disadvantage is

that the strategic reserve often lets regulators choose the mix of technologies or the location of the strategic reserve, while both capacity markets and energy–

only markets allow the market to decide.

More sophisticated versions procure generation capacity and let it bid into the wholesale market only if otherwise market clearing is not possible. This is a hybrid between price–based and quantity–based approaches. Yet it is inefficient. First, if the strategic reserve is not allowed to submit bids in normal ti

reserves are large, probably approximating VoLL, similar problems occur as those discussed for price-based approaches. Moreover, there is no model that we are aware of that predicts how the non–strategic capacity changes as a function of the strategic reserve. For example, if the strategic reserve is dispatche all scarcity rents and thus even suppresses new investments and distorts prices away from efficient spot market pricing. The likely result is that total capacity is reduced by the strategic reserve.

3.5 Further practical issues and common misunderstandings in practical design

3.5.1 Do renewables add to the problem?

Does the adequacy problem get more severe with an increasing share of renewabl amount of lost load), they cannot increase the appropriate level of the price cap, so renewables do not fall within our first reason for capacity markets, too low a price cap. However, renewables may contribute to the adequacy problem. For instance, renewables are subsidized via a feed–in–tariff which is fixed and guaranteed for 20 years or more plus an obligation of system operators partly explains why renewables' supply is not price–sensitive (another reason is that incremental costs are low). As a consequence, renewables create the same problem as the problem which is at the heart of the adequacy problem,

that is the price–inelastic demand. In fact, renewables can be thought of as completely price–inelastic negative demand.

Moreover, because neither wind nor the sun can provide firm energy, renewables coal and gas plants). At the same time, however, renewables increase price volatility, tend to reduce market price levels and worsen the capacity utilization of conventional capacity. This makes investments in conventional resources, ceteris paribus, less attractive, in particular when renewables are planned to produce a considerable share of consumed electricity. Also, politics, regulation ar the right technologies and the right price for new capacity. As a result, investors f

the needed future mix of generation, and future regulatory interventions. The capacity–market benefit of market coordination may then become useful.

3.5.2

Why pay existing plants?

There is confusion around giving capacity payments to generators that would remain in the market without such payments. Why are they being paid to do what they would do anyway? The simplest answer is one that answers a good many, perhaps even most, capacity–market puzzles. Existing plants are paid because that is what an ideal energy–only market would do. An energy–only market pays for peak capacity with scarcity prices that rise above the variable cost of a peaker. But when there is scarcity, every operable plant is running, and all are paid the same scarcity price, even though they would stay in the market without such payments.

A deeper answer would explain why ideal markets pay existing plants the same for their electricity as new plants. One could imagine inducing new plants to enter the market with long-term contracts that pay for both variable and fixed costs, but paying existing plants only a tiny bit more than their variable costs. They would not close, because some profit is better than none. This is called a regulatory taking or expropriation, and it can work effectively if investors are surprised. But once the policy is known, new plants will demand

contracts that protect them from future expropriations and likely charge a significant risk premium as well.

3.5.3 Won't capacity payments distort the technology mix?

A deep confusion concerning capacity markets is that they will not induce the right type of capacity. This confusion takes many forms and contains contradictory views, but there is one basic explanation of why the standard design induces the right technology mix. It does what an ideal energy–only market does. Start with an energy only market that sets a price cap of VoLL.

Peakers will cover fixed costs only when the price exceeds their variable cost.

But baseload plants also cover fixed costs when the spot price equals the variable cost of peakers but exceeds their own variable costs. This yields the well–known result where the market induces the optimal mix of plant with differing fixed and variable costs.

Now suppose that the price cap is reduced to 1000e/MWh. This will result in missing money. That money will be missing from scarcity hours and

only from scarcity hours. Suppose that a perfectly reliable generator would be missing 50000e/MW. In this case an 80% reliable generator would be missing 40000e/MW. Now let us implement a capacity market to replace this missing money. This market will not replace the money during scarcity hours, but will instead dole it out in equal monthly payments. Won't this distort the market's choice of technologies?

In the capacity market, a perfectly reliable 1MW generator will be paid 50000e/year, and an 80% reliable 1MW generator will be paid for 0.8MW of capacity and so it will receive 40000e/year. In short all of the missing money will be restored to the same generators that lost it when the price cap was lowered. Hence the capacity market will have no effect on the technology mix

relative to the ideal energy–only market. This result can be seen more easily if we assume all generators are perfectly reliable. In this case, all are running during scarcity events and all lose the same amount of missing money and all receive identical capacity payments.

3.5.4 Adequacy versus security

The motivation for a capacity market always stems from a concern for adequacy,

This goal can be achieved just as surely by purchasing only gas turbines or by purchasing an efficient mix of capacity. Having an efficient mix of capacity, as opposed to too many gas turbines, does not address the adequacy problem in any way. But it seems foolish to buy capacity that does not minimize consumer market.

This reasoning is considered uncontroversial until it is noted that the mix of, and behavior of, capacity should address security concerns. Then a chorus arises to assert that security was not the motivating problem so the capacity market should ignore it. But providing security is just a matter of minimizing the total cost to consumers of generation and blackouts. Why should this particular cost minimization be ignored? There is no logic to this view, so reasons are invented. The two most popular reasons to ignore security concerns are that

• addressing such concerns will cause most generators to stay warm all the time, and

• security is already handled optimally by the system operator.

To prevent the capacity market from addressing security it is suggested that the reliability option only apply when a warning is issued, say, four hours in advance of the scarcity price. This way generators that fail to perform

without a four hour warning will not owe any option payment. But let us look carefully at what happens with a four–hour delay. First consider a standard reliability option market. With or without the delay, if a generator supplies power in a scarcity hour it will be paid the scarcity price. The chance of this is what motivates generators to stay warm, so that motivation is not changed by a four–hour warning requirement. What could be changed is the hedge payment. But the hedge payment provides no incentive to perform because that payment (from generators to load) must be made whether or not a generator performs. This cannot cause a change in behavior except through psychological thinking that slow generators know they may lose out on energy market payments.

As always, they dislike this possibility and would like someone to subsidize their loss. Since the reliability option requires them to make option payments, cancelling those payments is a way to disguise the subsidy, an opportunity for obfuscation not provided by an energy–only market. They then argue that if they are not given the subsidy, bad things will happen in the energy market, even though cancelling their hedge obligation has no impact on their performance.

Fundamentals of Energy Regulation

Chapter 4

Electricity Sector Reforming

The current reform in the global electricity sector is often presented as a sudden change. Whilst it is certainly true that there are, in any country, step changes of rules, regulations, laws and structures that are commonly associated with a timetable of deadlines, they are in practice part of a continuum in which major structural changes take about ten years to agree, and ten years to implement and settle down. Similarly, whilst there have been changes and even reversals of direction, such as in parts of the USA, the global direction has been consistent for the last 30 years.

At high level, the reasons for reform are the growing belief, based partly on experiences to date, that by market orientation, the industry can more efficiently deliver the following policy objectives:

• Optimum electricity price,

- Security and sustainability of electricity supply,
- Environment (particularly CO2 and renewable energy sources),
- Demand management,
- Industry efficiency,
- Foreign policy and trade,
- Harmonisation with supranational institutions,
- Open access, and

- Industry governance and discipline.

Current reform is very much along the lines of the political ideology that has prevailed since the 1980's:

... that of competitive free market ...

Having begun as liberalised free enterprise in the 1880's, and fallen into municipal, federal hands over the next few decades, the liberalisation experiment began in 1970's with a partial opening of the generation sector to new entrants from whom the utilities were required to buy, and continued in the 1980's with the beginning of consumer choice. The 1990's saw the beginnings of competitive electricity markets with the growth of pool models, and the year 2000 saw the first bilateral physical market with the New Electricity Trading Arrangements (NETA) in England and Wales.

Change was then rapid with the proliferation of market opening and power exchanges across the world, and development of the market models for capacity, as:

- third party access,

• liberalisation,

• reform,

• deregulation,

• unbundling,

• re–regulation, and

• privatisation.

Many of these elements are now complete in a lot of countries and at this point, the countries are considering the virtues and drawbacks of the existing model, and in some places, taking the market model to new levels of technical complexity.

The challenge has been to open the market to competition in a measured and controlled manner such that each stage can be viewed in retrospect with

regard to intended and unintended impacts. In doing so, there is the recognition tl hence that liberalisation and deregulation must begin with power generation and supply.

Whilst deregulation has a specific meaning (stepwise opening of the monopoly sectors with regulated prices to competition), liberalisation has a more informal u electricity sector:

(a) Reduction of the role of the state, in terms of ownership, command and control, prescriptive solutions and direct cross subsidy,
(b) Creation and enhancement of competition by deregulation, vertical de–

integration (unbundling), horizontal de–
integration (divestment) and regulated third party access,

(c) Increasing choice for consumers and participation in short and long term demand management and responsibility to secure their energy.

The reform of the electricity sector in virtually every country in the world is bringing it closer to the free market paradigm. Since this journey takes a very long time, the development in all countries, except UK, falls far short of the point at which the issues of an unbridled free market become apparent.

From an industry perspective, some liberalisation objectives, are:

• Introduction of competition in generation,

• Introduction of customer choice,

• Dealing with independent power producer and stranded cost issues,

• Attraction of private investment,

• Entrenchment of universal service obligations,

• Promotion of integration of the grid,

• Reduction of debt.

It is quite apparent that both generation and supply are dependent on use of the networks. If there is common ownership of networks and generation,

or networks and supply, or both (as there is in a national monopoly), there is conflict of interest, so that the incumbent is incentivised to raise the entry barrier and excessively charge the new entrants.

Hence, new entrants need to be guaranteed free and fair access to power generation or consumption. This is by no means simple, even with the best will of the incumbents because the operation of power generation and of the transmission grid is optimised as a single entity. Hence to allow competition,

it is first necessary to restructure the national monopolies into vertically de–

integrated (unbundled) form, and for there to be some form of commercial arrangement between the unbundled tiers so that this arrangement can be followed by the new entrants.

4.1 Steps for electricity sector reforming

It is noted that the electricity sector is highly complex due to the special nature of electricity and that there is a very wide variation in key factors such as energy endowment and social model. There is no one size fits all, and since no policy maker can unilaterally impose a new model. Therefore, usually the reforming of the electricity sector takes incremental steps in the form of piecemeal engineering[1], learning from small mistakes, since in the electricity sector:

- Knowledge of whole system interactions is inadequate, imperfect, tenta-tive,
- Consequences are unknowable,
- Consensus is lower the more comprehensive the scheme and/or policy and/or plan.

Most countries are undertaking liberalisation of some form, and the starting point list below is in approximate order, but it differs from place to place:
(a) unbundling,

(b) corporatisation,

1The definition of piecemeal engineering suggest to apply the reforming changes electricity sector in a small amount at a time.

(c) ring fence chosen sectors,

(d) forced divestment and fragmentation of the incumbent utilities,
(e) privatisation,

(f) deregulation,

(g) re–regulation,

(h) further fragmentation,

(i) further unbundling and opening to competition, (j) re–
integration of some sectors and cross sectoral integration, (k) re–consolidation,

(l) horizontal integration with other industries,
(m) entry of financial institutions into the wholesale markets,
(n) pressure on retail deregulation,

(o) further deregulation of networks and metering, (p) revise model.

These changes are described below, ordered by logical sequence of explanation, r

4.1.1

Unbundling (de–integration)

Unbundling is one of the foundations of electricity sector reform. It is the separation of the vertically integrated industry sectors in such a manner as to facilitate competitive and non discriminatory access of participants to means of operation and route to market for the products or services. It is clear, for example, that if a generator wishes to access the consumer market without unbundling, a vertically integrated participant could easily deny access to the delivery of electricity.

At the highest level, the industry divides neatly into four sectors as below:

• generation,

• transmission,

• distribution,

• supply.

Also, fuel contracting is considered as a closely related upstream tier, and metering as a distinct tier lying between (and partly in) distribution and supply. Each unbundled stage can undergo extensive unbundling, by initially creating internal entities with service level agreements between them, and then outsourcing non strategic activities.

There are different degrees of separation in the unbundling processes that should be considered as stages:

Accounting separation: This involves the formal production of separate accounts may at first appear a relatively straightforward one, involving capital expenditure, depreciation, core operating budgets and some form of financial arra full statutory accounts for each division actually sets a clear path for full separation of the businesses since all resources must be accounted for in one business or other, and all flows of commodity or service from one to another should be treated as arms–length arrangements on commercial terms. In practice, the journey from informal inter–
business arrangements to formal commercial arrangements is a long one and henc are many degrees of accounting separation.

Functional separation: This involves the separation of the day to day business anc allocated between the divisions, there is no specific requirement for the inter–business arrangements to be on a commercial basis. For example, one could be a cost centre. However, the path is clearly laid open for full separation, since cost centres can optimise and prioritise effectively only if the services provided have clear monetary signals, thereby forcing the profit motive, a profit centre approach and then standalone businesses.

Operational separation: This involves separation of long term decisions, capital expenditure and operation of the businesses. This is a natural progression from functional separation, and the natural separation of board level decisions makes the path for board level separation.

Legal separation: The component where companies are completely separate from a legal perspective, although they could be ultimately owned, in whole or part, by the same entity.

Ownership separation: This means no significant common ownership.

As a general rule, partial unbundling of generation is the first step, by allowing and encouraging private new entrants. This can be regarded as stepwise from the other sectors. The unbundling of supply from distribution is generally a boundaries and various support services continues after the main unbundling is complete.

4.1.2 Corporatisation

Corporatisation is the process by which a publicly owned company with a public service franchise and purpose starts to behave like an investor–owned company. In some cases corporatisation is a necessary precursor to unbundling because the unbundled sectors cannot operate independently without being corporatised. This itself has many elements:

- The requirement of each entity not to lose money, with no cross subsidy from one entity to another,
- Migration of some long–term and high level responsibilities back to governments,
- Public service becoming a requirement rather than a purpose,
- Preparation for unbundling by internal transfer pricing, and service level agreements,
- Increased independence from the fiscal and monetary structure of the

nation. For example, payment of taxes, payment for fuel,

• End of requirement to create labour.

4.1.3 Ring fence activities under state control

Regardless of ownership, the state is the ultimate guarantor of the power system p control in some areas. The main three areas are described below:
National grids: National grids are commonly retained because it was felt, with some justification, that the grids form the focal point through which the industry is managed in the short and long term. By maintaining control of the grid, there was de facto control on every other sector, and by maintaining control of the grid, it was possible to form a coordinated view of security of supply, and then facilitation of whatever construction is required to alleviate this.

Nuclear power: This has commonly remained under national control because it ha decommissioning funds can only be assured by public sector retention, that consolidation of nuclear power maximises safety, and that overall public interest with respect to such a long term issue as nuclear power can only be served by having national ownership and accountability through the electorate.

Hydro power: The case for public sector retention for existing large hydro plant for the protection of public ownership of natural resources is not particularly compelling in countries which have been happy to privatise fuel and mineral extraction. However, the construction of large dams requires suc that sometimes the public interest can only be best served by public ownership. The control of hydro dispatch is, also, highly useful for the system operator. In addition, international aid, commercial loans and soft loans in relation to large hydro schemes and the sheer size of the schemes often calls for a high degree of state involvement.

In each case, there is now an increasing level of private ownership.

4.1.4

Forced divestment and fragmentation of the incumbents

Competition is enhanced by increasing the number of participants. If the number of participants is one or few, then the number of participants can be

increased by dividing up the incumbents into approximately equal or unequal sizes, or by forcing the incumbents to sell pieces of their business, such as power stations.

4.1.5

Privatisation

When the state monopoly has been corporatised, vertically unbundled and horizontally fragmented, then the component parts can be privatised, one at a time, or all together. There are essentially three types of privatisation:
(a) widely distributed, in which the share price is set low and there is a per capita allocation to the population,

(b) public offerings, in which investors (both strategic and institutional) buy the stock, and

(c) trade sale, in which the whole organisation is sold to a single company.

The privatisation process is a very sensitive one, since the electricity sector is seen as a national asset and there is often a risk (perceived or actual) that the stock is sold at low prices to individuals and companies with political connect
domestic shareholders.

4.1.6

Deregulation

The regulated sector is comprised of privately owned local monopolies, but has prices, revenues and/or profits regulated by government through the energy regulator. Deregulation is the process by which parts of the regulated sector open up to competition. Generation sector has generally been open to competitior regulated, generation competition is not usually classed as deregulation.

Almost always, deregulation begins by a gradual opening of the supply sector to competition, starting with the largest consumers, with a phased opening of the market to smaller and smaller consumers, and eventually to residential consumers.

4.1.7

Re–regulation

The deregulation process leads to the existence of two distinct sectors:

• The deregulated sector which is open to competition, and

• The regulated sector which has regulated prices or revenues.

Regulation is applied to both sectors, but is more of a monitoring, guiding and policing role in the deregulated sector than a price setting one.

4.1.8

Further fragmentation

The opening of the market, and the divestment of incumbents creates opportunitie market is best found, not by building a company from scratch but by buying a company and using that as a base for expansion.

The divestment from incumbents, also, created the ability (the money from the sales) and the desire (to expand when domestic expansion was not possible)

for foreign strategic investments by the incumbents. Historically, this caused the prices of investments to rise so much that many incumbents continued to sell assets voluntarily after the forced divestments were complete.

4.1.9 Cross industry horizontal integration

The opening to competition facilitates strategic entry into the market from large companies with relevant skills, such as oil majors, construction companies,

4.1.10 Re–consolidation

In some cases, the fragmentation of generation was so much that market prices fell to marginal costs, leaving many generators to lose money via their fixed costs. This caused a degree of re–consolidation. In addition to this, there has been extensive international consolidation, particularly in Europe.

4.1.11 Entry of financial institutions

The presence of financial institutions should be regarded as a measure of success

and electricity supply. There have been several circumstances in which creditors have acquired the assets of power companies as collateral by default.

4.1.12 Pressure on retail deregulation

From a regulatory perspective, the retail sector is the most important sector, since this is the interface between electricity sector and consumer.

4.1.13

Further deregulation of networks and metering
Since networks contain many functions, any function that can be outsourced can be deregulated. For example, transmission construction need not be the sole province of transmission network owners or operators. In addition, networks offshore networks and interconnectors. Further deregulation can be in connection meter data processing.

4.1.14

Revise model

There are a number of measures of success for electricity sector reform. In light of these, a review for the success should be based on the following issues:
(a) if there has been sufficient market reform to achieve success,
(b) if the market has reformed substantially, then how the model should be adjusted to improve electricity sector performance in delivering welfare,
(c) how to deliver further economic and environmental efficiency.

For example, the more fragmented the electricity market, the harder it is to enforce, and indeed deliver, universal service, due to the commercial impact of the required cross subsidy. There are a number of areas to examine and review, including:

Prices: what has been the effect of reform on prices, and what can be done?

Consolidation: how much is too much?

Demand management: will market mechanisms eventually deliver this, or must a prescriptive solution be applied?

Data: is the electricity meter flow data structure robust enough to recover from errors and to handle events such as change of supplier, occupier, or meter

Metering: to facilitate demand management, should parts of the metering sector be regulated or deregulated?

Macroeconomy: how much do increasing prices resulting from environmental lin

Environment: taxing externalities, or command and control.

Security of supply: assignation of responsibility or mechanisms for security of supply.

Issues regarding universal service and cross subsidisation, also, need to be investigated.

4.2

Conditions to reform

Early stage reform, such as corporatisation, and high level administrative unbund
exposing elements of transportation to competition and the development of wholesale derivative markets. To enter each stage of reform, there are prerequisit
Generation capacity: The implementation model depends greatly on the current generation capacity in relation to demand. If capacity is insufficient, then
generation. If capacity is excessive, then the divestment of ownership must provide current stability (possibly including vesting arrangements for stranded assets), both for the dominant incumbent and the new players, as wel

Investment environment: This is enhanced by stability of laws and taxes, mature local financial markets, freely traded currency, absence of hyper-inflation and low country risk.

Rationalised cross subsidies: The cost of low consumer prices arising from industry subsidy must be recovered by taxes, either from the subsidised consumers, or other consumers. In this circumstance, new entrance is not possible, and the cross subsidy system has to gradually unravelled.

In addition, issues regarding the will to disaggregate the electricity sector from the national economy to some degree, the high voltage grid infrastructure that is sufficiently present and reliable, the ability to collect tariffs for electricity, supported by the laws, police and courts, property access rights and disconnectio

4.3

The role of the state

Even in a fully privatised industry, the electricity sector is a collection of assets, existing property rights, right to build, franchises and obligations that has an inbuilt legacy relationship between private and public sectors that is de facto and informal as much as it is formal. These relationships built up incrementally as the industry developed, with a few step changes such as nationalisation and deregulation that in fact made relatively slight differences to this collection.

The state, therefore, retains an intimate connection with the running of the electricity sector as provided below:

• The state is the ultimate guarantor even if companies in the industry fail. In developed economies, this is particularly important in the consideration of current and likely achievement of national and international policy objectives tha the delivery falls short or can be enhanced.

• Electrification[2] is seen as an essential development for welfare and economic g

• In the absence of a complete market for bad products, such as emissions, the state must manage aggregate welfare by economic or prescriptive instruments.

2Connection of the population to the electrical infrastructure.

• Since the market does recognise fuel poverty, government intervention

is required to alleviate it by mechanisms such as subsidy, cross subsidy and discriminatory pricing.

• The electricity sector is a significant component of the fiscal macroeconomy of

The state performs numerous roles, such as, the participation of the electricity sec preparation of primary legislation to drive and control policy, conversion of direc that remain under state control, consumer subsidy if the requirement for cross subsidy within the electricity sector is reduced and cross subsidy comparison by taxation and concessions.

Electricity prices are not the only measure of the success of liberalisation[3], and prices are but one outcome of political model and industry structure. We can see in Figure 4.1 that there can be a wide variety of electricity prices, depending on the degree of state subsidy, which itself is dependent on the tax revenue (and welfare saving if unemployment is reduced) from the electricity sector. Indeed either the fully managed model or the open market model can in theory achieve low prices when pursued to its logical conclusion.

Regardless of ownership, the government has ultimate right of control. The government is the de facto ultimate guarantor of the industry performance in terms of the delivery of electricity to consumers. Governments can and do retain substantial influence of nationalised and other private companies. Such mechanisms include:

Shares: Full or partial ownership, golden shares (a share with significant voting rights but no significant economic value).

Legislation: Primary legislation (Acts of Parliament), secondary legislation (the detailed drafting of the Acts).

Taxes: New taxes, windfall taxes, change in tax rates, tax breaks, categorisation of tax liability.

3In April 2004 the two member states with the lowest cost of electricity where (a most deregulated one, in the UK, with a cost of electricity of 0.048e/kWh and (b) centralised one, France, with a cost of electricity of 0.051e/kWh.

State

Taxes

Subsidies

• corporation

• direct to industry

• indirect (industry wages)

• to industry suppliers

• direct (consumption)

• to consumers

• secondary (accumulator)

Electricity sector

Figure 4.1: The role of the electricity sector in economy.

Licences: Generally determined by legislation, moratoria, as soft mechanisms such as slowing down the ongoing series of permissions.

Arbitrating and determining: For disputes between different parties, and on interpretation of laws and regulations.

Administration: Slowing the operation of the company by means of enquiry and general administration.

Each of the above can have differential effects on different sectors and different players within the same sector.

4.4

System operators unbundling options in EU

The rules on legal and functional unbundling of Transmission System Operators (
to effective unbundling. With the adoption of the EU Directive 2009/72/EC

(the Directive), new rules have been introduced on unbundling for TSOs and for Distribution System Operators (DSOs).

Thus, the Directive as complemented by the EU Regulation 714/2009, provides for TSOs unbundling regime with the models of:

• Ownership Unbundling (OU),

• Independent System Operator (ISO), and

• Independent Transmission Operator (ITO).

All above unbundling models are subject to a certification procedure.

Their aim is to remove any conflict of interests between producers, suppliers and transmission system operators, in order to safeguard that the competitors of the vertically integrated utility will have:
(a) access on equal terms to the network,

(b) equal access to commercially relevant information,
(c) equal rights for investments in the networks.

According to the provisions of the Directive, in case the transmission system, on
member state may choose not to implement the OU model, and go ahead with the ISO or ITO model.

In a nutshell, under the OU model, the transmission activity (ownership and opera
activities of generation and supply. Under the OU model, each undertaking which owns a transmission system is required to act also as a TSO. The transmiss

supply of electricity or gas and vice versa.

Under the OU model, regulatory oversight is light. The transmission company, wl things for granting and manage third–party access on a non–discriminatory basis to system users, to collect access charges, congestion charges, and payments TSO compensation mechanism, and is also responsible to maintain and develop the transmission system. With regards to investments, th

term ability of the system to meet reasonable demand through appropriate investment planning.

The ISO model, allows a vertically integrated company to retain the ownership of its network assets, under a legally discrete and functionally indepen system is managed by an independent system operator (ISO) which shall be

fully independent (legally/functionally/control) from generation and/or supply int as specified under the OU model.

The ISO operates the transmission system under a lease agreement with the system owner, approved by the energy regulator. To ensure that the operator r regulation and permanent regulatory monitoring is to be in place. To avoid to the maximum extent possible any interference of the vertically integrated utility on system investments, the ISO model also confers all decision–making powers in terms of investments and network development on the ISO, while the national energy regulators have the power to formally approve the investment execute it.

The ITO model, allows for vertical integration to be preserved but provides for st utility structure autonomous decision making rights, managerial independence and unbundled accounts of the transmission company (the ITO), i.e., the company discriminatory third party access and that adequate investments are made.

It differs fundamentally from the ISO option because network operation is not structurally unbundled from supply activities, while network ownership remains with the same entity as the operator, as in the OU model. It is

important to notice that Article 17(3) of the Directive requires the ITO to
be organised in the legal form of a limited liability company as referred to in
Article 1 of Council Directive 68/151/EEC.

As far as the DSO is concerned, the Third Energy Package does not require
ownership unbundling as in the case of transmission, but provides for the
following obligations on the DSO:

• The DSO must be established in a discrete legal entity from the production and
company),

• The DSO must be separated at organization and decision–making levels
from the production and supply activities,

• The DSO must keep separate accounts for the distribution activity,

• The DSO must have at its own disposal the necessary resources to operate the d
financial resources, so that it remains independent from the vertically
integrated utility,

• The DSO must appoint a compliance officer, who will be in charge of the
implementation of the compliance program, he will be fully independent
and he will have unlimited access to information, and

• The DSO is strongly monitored by the energy regulator, that may impose
sanctions in case the DSO is not in compliance with its obligations.

4.5 Liberalisation and privatisation of the electricity sector in EU

Since mid–
990s, the EU Commission has advanced a programme for the creation of a liberal
which facilitates commercial and household customers to buy power from the
cheapest provider. Regulation would be replaced with competitive forces to

deliver consumer choice while driving prices lower. According to the revised EU directives, in fully liberalised markets, energy producers would be able to sell electricity and gas across national borders, increasing competition and lowering energy prices in the process.

This was to force incumbent energy utilities to become more efficient, encourage entire region. More recently, the debate on energy objectives of the European Commission has grown to include

• security of supply,

• greenhouse gas reduction, and

• sustainable production and consumption.

To facilitate these objectives the EU recognised the need to improve the quality of networks and the connectivity between such networks. Given the historic association between national grids and networks and national suppliers, i

as a facilitator to building a wider market, as the more end-consumers are reached, the greater the extent of competition between potential suppliers. In addition, economies of scale and efficiencies of modern networks with enhanced connectivity between national grids could help deliver objectives around energy s

4.5.1 Setting the stage

How did the plans made in Brussels progress over time? Against those upbeat aspirations, although the UK and Scandinavian countries opened their electricity markets and allowed competition and foreign investment in all the segments of the energy business, other European markets have remained dominat owned utilities.

For example, the Electricite de France (EDF) dominates 87% of France’s

electricity market, whilst in Germany, RWE and E.ON control between them 80% of the domestic energy market. Promoting competition in such concentrated and competition could materialise in the energy sector. Because of declining long run average cost curves in generation, increasing returns to scale meant bigger was better but lack of competition required regulation.

Historically, electricity industry operated as natural monopoly owning electricity quarters that national champions had an important role in securing European energy supply as long as the anti-competitive aspects of dominant players could be tempered through fair and equal third-party access (TPA) and cross-boarder connectivity. Thus, in order to open up the vertically integrated structures found within national boundaries, the EU Commission initiated various measures to promote equal and fair TPA to these grids so that owners or operators of networks would not abuse their natural monopoly and inhibit fair and equal access by other energy suppliers and thus foster competition.

As progress in achieving fair and equal TPA was slow, the EU Commission promoted new energy directives and regulations for both electricity and gas in 2003, requiring vertically integrated incumbents to unbundle/separate the operation of the transmission from other parts of their energy business and thus facilitate TPA. In 2007, the Commission took these measures further by

promoting ownership unbundling (OU), according to which incumbent utilities had to separate not only the operation but also the ownership of their various energy businesses. Integrated utilities were to be split into legally independent:

- generation,
- transmission and
- distribution companies,

so that access to networks could not be used to protect the competitive position of manifest, the business of selling energy needed to be separated from the business

4.5.2 Initial forays

Meanwhile, as an unintended consequence, to prepare for unbundling and gain a competitive advantage across national boundaries, horizontal acquisitions became commonplace as illustrated in Table 4.1. While some utilities made cosmetic steps towards unbundling, the most visible reaction across the European border mergers and acquisitions, which allowed incumbent energy utilities to con across the EU market, while in the UK (the most open energy market in the EU) almost all the unbundled domestic incumbents were ultimately acquired by their European still vertically integrated counterparts.

Horizontal integration across newly connected national markets appeared to be replacing vertical integration as a means of enhancing returns. In contrast to structure and behaviour, we see that a small number of large European integrated consumers via company-owned networks remains prevalent. The EU aspirations such as fair and equal thi party access to grids, the level playing field of network market liberalisation, along with European-wide contracting for power remain largely unattained.

While in certain markets like the UK the power grid is owned by a third-party without upstream supplies or downstream customers, in much of Europe network unbundling has yet to take place. Nonetheless the threat of vertical

Table 4.1: Examples of mega mergers and acquisitions in the EU since 2000

Acquirer	Acquired	Date of M&A
E.ON (Germany)	Powergen (UK)	2002
RWE (Germany)	Innogy (UK)	2002
E.ON (Germany)	Aquila (UK)	2003
Suez (France)	Electrabel (Belgium)	2005
RWE (Germany)	National Power (UK)	2005
E.ON (Germany)		

Ruhr Gas (Germany)

2005

Iberdrola (Spain)

Scottish Power (UK)

2007

Enel (Italy) and

Endesa (Spain)

2007

Accion (Spain)

GDF (France)

Suez (France/Belgium)

2007

EDF (France)

British Energy (UK)

2008

RWE (Germany)

Essent Energie (Netherlands)

2009

Vattenfall (Sweden)

Nuon (Netherlands)

2009

unbundling has led many companies to seek horizontal dominance across several home country advantages.

Looking across the economic landscape, we see an industry dominated by some long-established companies such as,

• RWE and E.ON Ruhr (of Germany),

• EDF and GDF Suez (of France/Belgium),

• Enel (of Italy),

• Vattenfall (of Sweden),

• Iberdrola (of Spain),

and a number of newer, but still integrated, utilities such as,

• CEZ (of Czech Republic),

• OMV (of Austria),

• PPC (of Greece),

• Polish Energy (of Poland) and

• MOL (of Hungary).

Meanwhile, the process of acquisitions and consolidations continued apace.

As a result, despite a new set of legislative measures proposed to promote competition, the electricity markets in many European countries remain barely competitive, without fair third-party access.

4.5.3

Later developments

Reviewing the latest developments, we find that the cross–border acquisition trend continues and is leading to the consolidation of energy utilities that are becoming regional in scope and are now expanding into Central and South-East Europe through a second wave of acquisitions. In the international business litera that to succeed, investing companies need to have some type of ownership, internalisation and location advantages over their competitors, they being domest

From this perspective, one can argue that the European incumbents are well positioned to invest in the lesser known energy markets of Southern and Eastern Europe. For example, the European incumbents have unchallenged ownership advantages in the form of:

- new and innovative technologies,
- expertise in network design and operations,
- engineering and managerial skills,
- advanced financial techniques and project management capabilities,
- environmental know-how, sometimes as a result of century-long investment in R&D and
- network activities.

It has been suggested that up to 2030% of their international investment is financed from internal resources, primarily generated from profits in their home country where they enjoy a monopolistic position. Importantly, many have mixed private–public ownership, due to their roots in publicly owned domestic entities and some were partly or wholly privatised prior to their internationalisation. Often such companies in total or partial state ownership benefit from their government support.

Gaining cross–boarder internalisation benefits appears to have particularly suited European energy incumbents as they looked at the opening of Central European markets. On regional basis, internalisation across adjacent borders could yield economies of scale and scope (technological know-how providers, consultancy, network maintenance, customer services, etc.). This is particularly tr delivered to the ultimate customer.

As for ensuring location advantages, host governments made sustained efforts to reform the industry with a view to attract foreign investors. In addition, compared to Western Europe, Eastern and Southern Europe offered better economic growth rates and demand for energy was on the rise, creating favourable conditions for producers and distributors alike.

Some investment was believed to have a more strategic character as it could facilitate exports of electricity to EU member states, whilst certain European energy companies were forced to invest abroad after losing domestic market share as a result of energy market liberalisation in the early 1990s. Low earnings in domestic markets due to low gas prices and a tax on nuclear power were also quoted as reasons to expand to Central and Eastern Europe. Table

4.2 shows the most important European energy investors in the region and the geographical spread of their activities.

While the attractiveness of the Eastern European countries to European incumbent majors conforms to the foreign direct investments (FDI) paradigm, the acquisitions by the major European incumbents remain challenging from several perspectives. Despite perceived ownership, internalisation and location advantages, the interest of European incumbents in the lesser known energy markets of Southern and Eastern Europe requires further scrutiny.

For the host countries keen for investment in infrastructure, it was important to cr reform, minimise sovereign risk for investors and mediate the concerns of domes

Table 4.2: Infrastructure (energy) FDI across South and Central Eastern Europe

EU energy utility

Segment of energy mar-

Country of destination

ket

Enel (Italy)

Electricity distribution

Bulgaria, Greece, Ro-

and generation

mania, Slovakia

Eni (Italy)

Electricity and gas gen-

Romania,

Greece,

eration,

transmission,

Turkey, Croatia, Slove-

distribution

nia

CEZ (Czech Re-

Electricity distribution

Bulgaria, Poland, Al-

public)

and generation

bania, Serbia, Kosovo,

Hungary, Slovakia, Ro-

mania

RWE (Germany)

Electricity distribution

Poland,

Romania,

Czech Republic, Hun-

gary

E.ON (Germany)

Electricity and gas dis-

Hungary, Slovakia, Ro-

tribution

mania, Czech Republic,

Bulgaria

EDF (France)

Electricity

generation

Hungary, Poland, Slo-

and distribution

vakia

ever, this necessary condition may not be sufficient to yield the kind of returns to which the utility majors were accustomed.

This raise the question of why these utilities are eager to operate in markets where the competitive segment is to be limited at first and where competitive mar addition, the process of internationalisation for energy companies can be a lengthy and difficult one. If, following EU directives, competitive market conditi earning supra–normal returns the majors could no longer expect in Western European markets? It is, perhaps, likely that investors might have envisioned other means of creating market power, such as replacing vertical integration with horizontal integration across the region.

4.6 Regulation of isolated power systems

The regulation of small isolated power systems features some notable differences

- greater level of intervention in planning the sector at the generation stage, and

- high electricity cost due to the dependance on oil products.

Isolated grids feature a set of characteristics that usually imply a greater energy dependency and vulnerability, requiring the need for specific planning.

Generally, these systems do not have access to every technology available, nor can they be connected to continental grids, such as the European grid, if necessary. Isolated electrical systems exhibit a series of characteristics that contribute to increase the cost and the uncertainty of the electricity generation.

The main problem facing these types of electrical systems, is the increased cost of the electricity supply caused by, among other things, high fuel transportation c endogenous energy sources.

The smaller the electrical system size, the more the expenses will be. The power generation units cannot exceed a certain size since the loss of a unit or a group of units would mean the loss of a high percentage of the entire system.

As a result, economies of scale cannot be adequately exploited like in large electrical systems, which serve to complicate the technical control of the grid in terms of frequency and voltage. The isolation also requires maintaining a greater reserve capacity to ensure an adequate supply. Also, the greater flexibility offered by interconnected grids is not available in isolated power systems. Thus, such isolated systems require different planning and treatment from continental grids.

Territories belonging to a country normally charge the same rate, meaning that isolated systems, due to the higher supply costs, must be subsidized by the citizenry as a whole, as in Greece or Spain. Obviously, in such a situation, reg these conditions, the introduction and development of renewable endogenous energy sources is an important complement to conventional models based on fossil fuels. This complementarity offers a solid tool for achieving the main energy policy goals, such as, economic efficiency, respect for the environment

and security and diversification of the supply. And yet, the interruptible and irregular nature of renewable energy sources, along with the isolation of the economy, can significantly condition the penetration rate of renewables into these electrical systems. So, given the current state of technology in renewable sources, these economies continue to rely on conventional plants as the basis for their electrical systems. Hence, ideally, these plants should be as efficient as possible and be able to provide the greatest guarantee of the security of supply.

For such small isolated power systems oil derivatives are used almost exclusively and the size of the generating units. This extreme reliance on oil is not unusual. I

islands is 74%. Trinidad and Tobago rely 100% on natural gas, while Jamaica is 98% dependent on oil and 92% of the power generation units in Cyprus use fuel oil.

Chapter 5

Energy Markets Competition

There are two fundamental organizational models used as business environments, Microregulated: the traditional regulated utility that is managed by the state and federal governments at a microdecision level. The utility proposes new p to the state for approval. A key approval is the return on investment allowed by the utility so as to pay investors to borrow money. Once the state approves any projects or price changes, then the federal government can federal laws, especially environmental protection laws. The operation and planning of such a utility is transparent, if the government regulators technica questions raised by any of the regulators. Such a utility has to answer to the customers through the elected officials (governors and presidents) via public forums to explain why key decisions were made and why the costs have been incurred. This work refers to microregulated as regulated to conform with the common use of the term.

Macroregulated: an environment where the intercompany contracts such as purchasing, shipping, and buying are the key regulated items. Regulators typicall ventures, and other inter- company arrangements to mitigate market

monopolies, shipping congestion, and corporate pricing controls. Regulators are p referred to as competitive market structure. However, this discussion acknowledges that such competition may be lacking due to the supply chain structures, the auction mechanisms, or the market clearing rules.

Competitive markets have to be regulated by governments to achieve efficiency, to eliminate contract confusion for gaming and to provide a naturally clearing market without monopolistic actions.

5.1

Regulated environment

Utility operation in a regulated environment acknowledged that these companies utility was awarded a franchise for a selected area, normally due to historical growth. The utilities in such an environment are microregulated by the governme profit margin allowed, and even profit to be distributed to shareholders, if any.

Energy regulators have complete transparency of all financial contracts, all accounting procedures, data bases, all planning and operating decision processes reviewed once a year or when an event causes a change in the revenue requireme accounting discrepancy or mismanagement has occurred. It is common for tariffs to be reduced when fuel prices decline unexpectedly or deflation occurs.

5.2

Competitive market environment

Specific legislation called for competition in the power industry from the wholesa suppliers. One approach is the application of brokerage systems to the power industry to promote competition. To accomplish competitive markets most of the vertically integrated utilities have been broken up.

The energy regulation is the top tier of the structure. The utilities in such

an environment are macroregulated by governments at the level of business protocols, market standards, contract standards, and transparency to mitigate monopoly power. If the retail markets were also re–regulated, then the tariffs for each type of customer would be defined at a more general level such as most retailers face in the standard business code of law. Energy regulators have limited transparency of financial contracts, accounting procedures, data bases, planning and operating decision processes, risk analysis and management all records if insider trading or monopoly power is exercised in a fashion not allowed by the laws.

The generation companies primarily produce electric energy (GENCO).

The transmission companies (TRANSCOs) own and operate transmission lines.

The distribution companies (DISTCOs) own and operate distribution lines.

The brokers (BROCOs) buy and sell electricity for profit. The energy service companies (ESCOs) purchase electricity acting as agent for consumers. Alternati (EMCOs) and load serving entities (LSEs).

The primary entity that will have direct dealings with the end users under the new market structure is the energy service company (ESCO). The ESCO

collects its revenue from the distribution customers for the energy and ancillary s electric energy through the auction market and reselling it to the other ESCOs, GENCOs, etc. To purchase the desired electric energy to serve its purpose, the ESCO may purchase through an auction market or through direct contracts or management programs or the ownership of generation units. Additionally, all supportive services (e.g., load following and regulation) have to be procured to enable delivery of the energy across the transmission grid.

In the re–regulated environment, every customer is free to choose any ESCO to serve the energy demand. In addition, the energy purchased from the auction market bears the risk of market price fluctuation. These, from the demand factors to the supply factors, are the risks that the ESCO has to undertake in the new market structure. Since deregulation will render the governmental protection (financially) obsolete, risk management and assessment

have a fixed and a variable operating cost based on the selected mix of capital expenditures and operating expenditures. The GENCO sees a demand curve

by the buyers, in this case the ESCOs. The GENCO is a demand curve seen by the fuel suppliers. The ESCOs see the GENCOs through the supply curve.

The ESCOs are a supply curve to all customers.

The basic models of the supply and demand curves are generated from basic cost components. The supply curve of the marketplace is the sum of the individual supply curves of all GENCOs suppliers. The demand curve of the marketplace is the sum of the individual demand curves of the buyers ESCOs pool purchasers and other consumers representatives. These curves are assumed in this work to be the actual cost curves, including profit to pay for capital contracts (stocks, bonds, mortgages, etc.). These curves may be altered if the supplier or the buyer can implant a perceived differentiation of product or if there is a differentiation of product. Such details are beyond the scope of this work.

5.3

Competitive market solutions

Each company has a multifaceted optimization problem of using scarce capital resources, scarce operating resources, and scarce labor resources to make and deliver a product. A vertically integrated utility:

• gathers the raw resources (fuels),

• transports the fuels to processing plants (distilleries), and

• transports the raw fuel to the power plant (manufacturing).

The electricity produced is then transported and distributed by the transmission an gorized as:

• residential (homes and apartment),

• commercial (retail shops),

• industrial (business services and maintenance), and

• manufacturing (steel mills, auto assembly, etc.).

A vertically integrated utility usually does not own the oil wells, gas wells, or coal mines. There is a market between the utilities and these resources as

oil is also demanded by the petroleum industry, gas is also demanded for direct consumption as a heat resource or process steam resource, and coal is used as a heat resource and as a process resource for metal fabrication and milling.

These uses existed before the advent of electricity as an energy infrastructure.

Natural gas was the fuel for heating and light. Coal was used for heating.

Recently, the use of power plant steam or hot water as another resource has resurfaced as a combined heat and power unit.

A horizontally regulated environment separates the layers from the vertical organization and places intermediate markets between the layers. Markets in this work include all contracts traded on an organized trading floor to contracts traded over the telephone or internet between companies, also known as over–

the–counter trading. There are many possible segmentations. The segment adopted depends on the historical development to date and the deregulation procedures adopted by the governments. The natural gas industry was the first energy industry to offer lighting and heating to customers. Thus, the harvesting companies were separated historically due to geographic locations and transportation (pipeline) limitations. The development of hydro required extensive capital budgeting that could only be covered by the federal government electric energy in rural parts of the country but also to control flooding during years of high rainfalls. The original wellhead companies served local cities directly until more distant cities and states offered higher revenues, causing the splitting of the wellhead companies from the local cities. Additionally, the wellhead companies were traditionally high–risk drilling companies that no one city could underwrite. Once Edison and Westinghouse developed the electric generator, cities were converted to electric energy from gas energy on a block–by–block basis. Some gas utilities fought the new entrant to the energy industry. Some purchased the competitors to maintain a monopoly status.

Rural areas were electrified by law enforcements.

It is noted that the original gas and electric utilities were not regulated. It

is noted that many countries formed electric companies as part of their federal government due to the view that utilities are a natural monopoly. Given the large capital investment, this can be argued even today. The majority of a utility investment is in the distribution network and the staff to interface with the customers and the customer equipment.

Re–regulation segmented the vertically integrated utility into three categories:

(a) generation,

(b) transmission, and

(c) distribution.

The analysis of a company does not depend on the business environment within which it operates (regulated or competitive). The business environment on a competitive market. The basic tools of analysis are the same with a few alterations in data generation.

There are several interesting views to study supply chains. The first is to isolate the suppliers and identify the costs and benefits of working with that supplier. This is normally done as a discrete auction even if a commodity exchange is not used. This work uses the term market to describe any means for suppliers and buyers to exchange information leading to a contract for the exchange of raw resources needed for production. Such means may include organized exchanges and may be strictly over the counter, such as an internet–

based exchange or strictly through trade magazines. A partial equilibrium system solution is an alternative analysis. These analyses are static solutions and do not show the intricacies of repeat solutions of multiple markets or of time domain analysis of markets.

It is noted that forecasting of the market prices is a key fundamental component c
by the consumer. Product prices have to recover all costs of production including

price to recover all expenses and profits stated for shareholders at a minimum.

The competitive force of potential entry is based on barriers to entry. These are related to economies of scale, the existence of learning and experience curve effects, brand preferences and customer loyalty, capital requirements, cost disadvantages independent of size, access to distribution channels, and government actions and policies.

The competitive force of substitute products is centered on the price and availability of acceptable substitutes for each product and places a ceiling on the prices that the producers of the product can charge. Unless the sellers of each product can upgrade quality, reduce prices via cost reduction, or otherwise d in sales and profits because of the inroads substitutes may make. The compe-

tition from substitutes is affected by the ease with which buyers can change over to a substitute. A key consideration is usually the buyers switching costs, the one–time costs facing the buyer in switching from use of a product over to a substitute. The economic power of suppliers is based on the ability for a group of supplier firms to exercise more bargaining power:

- When the input is, in one way or another, important to the buyer.

- When the supplier industry is dominated by a few large producers who enjoy reasonably secure market positions and who are not beleaguered by intensely competitive conditions.

- When suppliers' respective products are differentiated to such an extent that it is difficult or costly for buyers to switch from one supplier to another.

- When the buying firms are not important customers of the suppliers.

- When one or more suppliers pose a credible threat of forward integration.

The economic power of customers is based on the leverage and bargaining power of customers and tends to be relatively greater:

• When customers are few in number and when they purchase in large quantities

• When customers' purchases represent a sizable percentage of the selling industry's total sales.

• When the supplying industry is comprised of large numbers of relatively small sellers.

• When the item being purchased is sufficiently standardized among sellers that customers can not only find alternative sellers but they can also switch suppliers at virtually zero cost.

• When customers pose a credible threat of backward integration.

• When the item being bought is not an important input.

• When it is economically feasible for customers to purchase the input from several suppliers rather than one.

The competitive force of rivalry in the existing industry is centered on efficiencies and economies of scale. Rivalry tends to intensify as the number of competitors increases and as they become more equal in size and capacity.

Rivalry is usually stronger when demand for the product is growing slowly.

Rivalry is more intense when competitors are tempted by industry conditions to use price cuts or other competitive weapons to boost unit volume. Rivalry is st differentiated that customers incur low costs in switching from one brand to another. Rivalry increases in proportion to the size of the payoff from a successfu to get out of a business than to stay in and compete. Rivalry becomes more volatile and unpredictable the more diverse the competitors are in terms of their strategies, personalities, corporate priorities, resources, and countries of origin. Rivalry increases when strong companies outside the industry acquire weak firms in the industry and launch aggressive well–

funded moves to transform the newly acquired competitor into a major market co

5.4

Imperfect competition

Imperfectly competitive market environments are more common than perfect competition. A single firm serving an entire market for products that have no close substitutes typifies a monopolized market. Alternatively, monopoly power is achieved by economies of scale, economies of scope, cost complementa the price is set by the market conditions and equating marginal revenue to marginal cost sets quantity, a supply curve does not technically exist. However, d monopoly rents to increase the marginal cost to the price can form the basic analysis of the monopoly power impact.

Monopolistic competition is a very common condition when there are many buyers and sellers, each firm produces a differentiated product, and there is free entry and exit. Differentiated products may be established in reality or in perception. Customer selection may be based on time of day, reliability, and quality to differentiate electric energy products from different providers. Firms engage in comparative advertising, brand equity, niche marketing, and green marketing to virtually differentiate products. Other market types are defined

under separate categories, such as oligopoly. Only a few firms supplying the product denote an oligopoly market, and each firm is large with respect to the total industry. Oligopolies also spawn most of the research due to tacit and explicit collusion. Collusion reduces the competitive market to a monopolistic market. Tacit collusion occurs when there is sufficient public disclosed informatio

Explicit collusion is when two or more firms engage in price fixing.

Supply curves are inelastic in the short run as production and consumption cannot change quickly. If demand increases, then price increases until a new equilibrium is found. As the price increases, more fuel can be procured to meet the increased demand as drilling costs increase. Continuous pressure on

supplies with increased price will entice new entries into the market to meet the new demand. Such new entries would include renewable energies, such as biofuels, solar, wind, and hydro resources. Short–run response assumes that equipment is not improved, expanded, or augmented. Long–run response assumes that new equipment may be added or production efficiencies can be implemented. Technology changes are not normally included in the long-run response, as technology changes are fundamental production changes that are hard to predict.

5.5 Evolving markets

The original business environment outlined earlier was a single, monopolistic, vertically integrated utility providing gas and electricity. Only a few countries have a vertically integrated utility from mine or gas well to customers. As natural gas was the original energy industry, those companies are typically separate from the electric companies. Natural gas was the light and power company before the DC dynamotor was invented. Some natural gas companies were visionary to be aware of the impact of electricity and became the gas and electric company. Since natural gas heating is an economic substitute for electric heating, natural gas is still a viable alternative in many locations. The natural gas companies within the United States were connected radially to gas wells owned by suppliers. Thus, the term horizontally integrated industry has been used for this structure. It is noted that natural gas has been sold through markets for some time, even before the natural gas industry was re–regulated.

The rise of markets in horizontally integrated industries naturally arises

as companies find economies of scale and reliability opportunities to interconnect
this book. Such markets are negotiated between companies individually or equivalently through an over–the–counter process. It is noted that many over-the-counter markets are simply bulletin boards, such as newspaper ads, or electronic internet sites (eBay is a prime example) where buyer and seller can meet to transact business. When markets are volatile, additional players enter

for profit as speculators. Such players provide information on inefficiencies of markets, operation, or planning using better information than the traditional players. Uncertainties in government regulations also give rise to speculators who understand the macroeconomic implications of the global economy. It is noted that imperfect markets also give rise to speculators due to corruption, national frictions, etc.

The original markets were established several thousand years ago. These markets dealt with agricultural products, such as wheat and olive oil. Many of us have been to fish markets, farmer markets, flower markets, etc. This is the definition we will use for markets in this work. Markets became more organized as the number of the participants grew. Markets standardized on the auction mechanisms to facilitate trade and to regulate the business conducted under the market organization. Auction mechanisms are one of the key interests of economic studies. There are five mechanisms that will be presented within this work. The structure of the offerings is also a key definition of the market mechanism as is the role of an auctioneer, if there is one.

Each market is defined by a contract by the participants. The contract specifies the auction mechanisms, the rules for submitting buy quotes (bids) or sell quotes (asks), the matching of each bid and ask, the rules for recording the transaction, the rules for settlement if discrepancies arise, the quality of the product transferred, the time of delivery, the quantity of product delivered, etc. This work will assume that one-sided auctions dominate most industries.

One–sided auctions have an auctioneer representing the buyers or the sellers.

The counter party is represented by individuals representing the sellers or the buyers, respectively. We will first assume that the auctioneer is representing the buyers, as is the case for most electric spot markets. This work also recognizes the dominance of two–sided markets for most commodities. Two-sided markets are structured as a traditional fish or farmers' market with buyers and sellers in a central location, called a trading floor.

The delivery of the product can occur at different point in time. Ex-

changes that immediately trade the product are called spot markets. The fish and farmers' markets are traditionally spot markets as the produce is traded immediately. Thus, the first step is to identify the commodities to be traded.

Oil, coal, natural gas, hydrogen, water, and biofuels are easier to identify as they have physical substance and are transported as solids, liquids, or gases.

However, electricity is not as easily defined. The first step is to identify the duration of the electric energy to be traded. The basic energy contract is the energy for the hour as if the hour is block loaded. This is the traditional interchange view as discussed later. The energy balance or demand following a contract is the change of the demand from the start of the hour to the end of the hour, shown by the rising straight line over the hour. The possibility of an outage contingency, shown as a decreasing trend is offset by a contingent contract, the first of which is known as spinning reserve. It is noted that the inertia of the system is the first response but is not yet traded as of this writing. Also the governor response is the second response as the steam or water valve is opened to provide more mechanical power to the turbine. The frequency response is the next action implemented by automatic generation control. All of these ancillary services are needed to provide the energy balance that is instantaneously required to satisfy the laws of physics. They should all be traded in a competitive market to establish the inherent response of the power system to changes in demand, transmission availability, and generation resources.

The deconstruction of the demand curve into these commodities is needed to understand why these markets are needed to maintain system integrity.

The advent of wind and solar generation has given rise to a need for inertia markets' as power electronics isolate spinning inertia from the electric power system.

Contingent contracts are needed for reliability (security) such as spinning reserve and ready reserve. Contingent contracts often offer demand resources as well as static capacitor or dynamic equipment resources. Batteries and flywheels offer inertia response as a prime example. Thermal energy storage offers balancing resources. There are many other systems being implemented for these ancillary markets.

As a switch is turned on at home, this increase in demand is served by the conversion of the system rotating mass. This causes the frequency to decrease.

This decrease is sensed at the plant by the governor and then the steam valve is opened to increase the plant output. The governor is comparing the present

frequency with the actual frequency to detect these changes. Once the valve is opened sufficiently, the production is once again equal to demand. Now that the power system is at an increased demand operating point, a system–

wide controller (automatic generation control) adjusts the governor setting to restore the frequency to the desired base value (50Hz or 60Hz). The governor settings are found by finding the most efficient, cost–effective allocation of generation based on fuel costs, costs of conversion, and costs of transportation across the transmission grid. The slow response of the governors is masked by the fast response of the rotating inertia (mass).

The slow response of the power plant boilers is masked by the faster response of number of boilers committed to operation by optimal scheduling of power plants given the daily demand cycle. The daily demand cycle is based on the human work cycle. We sleep about 8h, we work 8h, we play 4h, and we move from place to place over 4h. Let us segment the demand into small, almost that electric energy is produced and consumed almost instantaneously. The problem, once again, is to level the demand curve.

The first task is to determine the total energy for the hour to schedule the commitment of resources. The commitment of resources is subject to the capability of the generation to respond as the demand increases, decreases, or stays constant. Note that the generation has to additionally respond to the cyclic changes during the hour. The cyclic demand occurs faster than a pumped hydro unit can be switched from pumping to generation. Thus, another resource has to be used.

Historically, this additional resource is the fossil–fueled units. However, batteries and flywheels are also used to reduce the cost of operating the fossil–

fueled power plants. Pumped hydro storage cannot be changed quickly without co
hourly basis as a generator or pump. Changes in pumping or generation can provide response capability in a limited fashion, just as fossil–fueled plants can respond.

Batteries cannot be changed quickly without loss of expected life from generation to storage. Since batteries are not as fast as flywheels, they are often used for the cyclic component and not the random component.

Thus, the demand is finally separated into two components: cyclic and random. Flywheels provide energy by adjusting their speed just as the ro-

tating mass of each generator provides energy through adjustment of speed.

Flywheels then respond only to quick and random changes so the generation can be operated with minimal governor response resulting in almost constant generator speed. Synchronous condensers used for voltage control also offer inertia response and frequency control. Thus, there is incentive to never retire an old generation unit.

Each of the aforementioned is solved as a competitive market with bids from each resource to establish an inherently stable system at all future points of time within the operation planning horizon.

Chapter 6

Energy Tariffs

Tariff structures are sometimes very complicated. They are difficult to understand
utilities themselves often confuse the customer rather than clarify the bill.

More and more energy customers are trying to understand their tariff schedules, and sometimes they even participate in public hearings regarding

the development of future energy tariffs. For example customers should know what electric tariff they are under and how much they are charged for the various factor, sales tax, etc. End users should also know the details of their other energy tariff structures such as natural gas, fuel oil, coal, and/or steam/chilled water. While the majority of the discussion focuses on electricity, attention is also given to natural gas.

6.1

The role of energy regulator

Electric and gas utilities are licensed and regulated by the energy regulator[1].

Utility rates are set in two steps:

first, the revenue requirements to cover costs plus profit is determined,
second, tariffs are designed and set to recover these costs or revenue requirement

1National Regulatory Agency (NRA).

The energy regulatory agencies set a rate of return for utilities. The rate of return is the level of profit a utility is allowed to make on its investment in producing and selling energy. In developing tariffs, the costs of serving differe classes. Tariffs are then structured to recover these costs from the appropriate cus based tariffs. Often,
these costs are average, or embedded costs, and do not consider the marginal costs associated with, e.g., providing electricity at different times of the day and different seasons of the year. Tariff design is subject to many competing viewpoints, and there are many different objectives possible in tariff setting.

When a utility requests a tariff increase (or decrease) and/or tariff restructure, the the proposal, and to take testimony from the utility staff, consulting engineers, customers and the public at large. The utility presents its case for why it needs a tariff increase (or decrease) and/or tariff restructure, and explains what its

additional costs are. If these costs are judged "prudent" by the energy regulatory a
adding some of that cost to its rate base, which, is the accumulated capital cost of facilities purchased or installed to serve the customers and on which the utility can earn its rate of return.

Many large utility customers participate actively in the tariff hearings for their utility. Energy regulatory agencies are very interested in comments from utility customers regarding quality of service, reliability, lengths of outages, and other utility service factors. Energy regulatory agencies vary greatly in their attitude toward utility tariff increases. Some countries favour the utilities and consider their interests to be first priority, while other countries consider the interests of the customers and the public as paramount.

6.2

Electricity tariff structures

6.2.1

Electric utility costs

Perhaps the best way to understand electric utility billing is to examine the costs faced by the utility. The major utility cost categories are the following:
Power generation plant: This is often the single biggest cost category. Because ele

sophisticated with more pollution control requirements, the cost of building and c
supply the peak needs of its customers while maintaining some equipment in rese
even blackouts may occur. This added capacity can be provided with expensive n
facilities, many utilities are urging their customers to reduce their peak demand so that the existing facilities will provide sufficient capacity.

Transmission lines: Another major cost category is the cost of transmission lines to carry the electricity from where it is produced to the general area where it is needed. Electricity is transmitted at relatively high voltages to minimize resistance losses. This loss can be large or small depending

on the transmission distances involved.

Substations: Once the electricity reaches the general area where it is needed, the voltages must be reduced to the lower levels which can be safely distributed t down transformers at substations. A few customers may receive voltage at transmission levels, but the vast majority do not.

Distribution systems: After the voltage is reduced at a substation, the electricity is delivered to the individual customers through a local distribution sys through the use of appropriate step–down transformers at the customer's specific location. Components of the distribution system which contribute to the u and capacitors.

Meters: Meters form the interface between the utility company and customer.

Although, the meter costs are relatively small, they are considered a separate item called the customer charge. The cost of a meter can range from under e50 for a residential customer to e1300 or more for an industrial customer requiri

Administrative: Administrative costs include salaries for executives, middle mana

staff. Office space and office equipment, taxes, insurance, and maintenance equip

Primary energy: Once the generation, transmission and distribution systems are in fuel the boilers and generate the electricity. In the case of hydroelectric plants, the turbine generators are run by water power and the primary energy costs are small. Similarly, fuel costs for wind, solar and biomass power are small. Fossil fuel power generation plants have experienced dramatic fluctuations in fuel costs depending on how national and world events alter the availability of oil, gas, and coal. The cost of fuel for nuclear power plants is reasonable, but the costs of disposing of the radioactive spent fuel rods, while still unknown, are expected to be relatively larg

Interest on debt: This cost category can be quite large. For example, the

interest on debt for a large power plant costing e500 million to e1

billion is substantial. Utilities commonly sell bonds to generate capital, and these bonds represent debt that the company must pay interest on.

Profit: The utility must generate enough additional revenue above costs to provide a reasonable profit to stockholders. The profit level for private utility companies is determined by the energy regulator and is called the rate of return. Public–owned utilities such as state–own utilities, municipal utilities or rural electric cooperatives usually set their own rates and their profit goes back to their customers in the form of reduced taxes or customer rebates.

Once the costs contribute to an electric bill are identified, the next step is to allocate those costs to the various customers. The billing procedure, should be designed to reflect the true costs of generating the electric power. If the customers understand the problems faced by the utilities, they can help the utilities minimize these costs. Most of recent tariffs capture the true costs of power generation much better than has been done in the past, but more changes are still needed.

6.2.2 Customer classes and tariff schedules

An electric utility must serve several classes of customers. These classes vary in complexity of energy use, amount of consumption, and priority of need.

The typical customer class categories are:

(a) residential,

(b) commercial, and

(c) industrial.

Some utilities combine commercial and industrial customers into one class while other utilities divide the industrial class into heavy industrial and light industrial customers. The energy regulatory agencies and utilities develop different tariff schedules for each customer class. Electric tariff structures vary greatly from utility to utility, but they all have a series of common features.

The most common components of tariff schedules are described below, but not all of these components are included in the tariff schedule for every customer class:

Administrative customer charge: This fee covers the utility's fixed cost of serving the customer including such costs as providing a meter, reading the meter, sending a bill, etc. This charge is a flat monthly fee per customer regardless of the number of kWh of electricity consumed.

Energy charge: This charge covers the actual amount of electricity consumed mea

• an average cost, or base rate, for the fuel (natural gas, fuel oil, coal, etc.) consumed to produce each kWh of electricity,

• a charge for the utility's operating and maintenance expenses.

Many utilities charge a constant rate for all energy used, and this is called a flat rate structure. A declining block approach may also be used. A declining block schedule charges one price for the first block of energy (in kWh) used and less for the next increment(s) of energy as more energy is used. Another approach is the increasing block rate where more is charged per increment as the consumption level increases.

Fuel cost adjustment: If the utility has to pay more than its expected cost for primary fuel, the increased cost is "passed on" to the customer through use of a prescribed formula for a fuel adjustment cost. In times

of rapidly increasing fuel prices, the fuel adjustment cost can be a substantial pro adjustment cost to reduce tariffs when fuel costs are lower than the cost included in the base rate.

Demand charge: The demand charge is used to allocate the cost of the capital facilities which provide the electric service. The demand charge may be:

• “hidden” in the energy charge, or

• it may be a separate charge.

For example it may be expressed as 5e/kW/month for all kW above 10kW. For large customers, the demand charge is generally based on their kW demand load. For smaller users such as residential and small commercial customers this charge is usually averaged into the energy charge. Understanding the difference between electric demand, or power in kW, and electric energy, or consumption in kWh, is important to understand ho of an automobile where the speedometer measures the rate of travel in km/h, and the odometer measures the total km traveled. In this instance, speed is analogous to electric power, and km traveled is analogous to to of use of electric energy, and conversely, energy is the time integral of the power. Finally, the value of the power or demand a utility uses to compute an electric bill is obtained from a peak power measurement that is averaged over a short period of time. Typical averaging times used by various electric utilities are 15 minutes, 30 minutes and one hour. The averaging time prevents unreasonable charges from occurring because of very short, transient peaks in power consumption. Demand is measured by a demand meter.

Demand ratchet: An industrial or commercial rate structure may also have a demand ratchet component. This component allows the utility to adequately charge a customer for creating a large kW demand in only a

few months of the year. Under the demand ratchet, a customer will not necessarily be charged for the actual demand for a given month. Instead

the customer will be charged a percentage of the largest kW value during the last 11 months, or the current month's demand, whichever is higher.

Power factor: The power factor is important because it imposes costs on a utility that are not recovered with demand and energy charges. Industrial custome

They create greater power factor problems for a utility because of the equipment they use. They are also more likely to be able to correct the problem. If a large customer has a poor power factor, the utility may impose anot factor is a complex subject to explain, but it can be a vitally important element in a company's electrical bill.

All of the above factors are considered when a utility sets its base tariffs, the tariffs the utility must charge to recover its general cost of doing business.

The base tariffs contain an energy charge that is estimated to cover the average cost of fuel in the future. The fuel adjustment charge keeps the utility from losing money when the price of their purchased primary fuel is higher than was estimated in their base tariffs. Table 6.1 presents a generalized breakdown of these tariff components by customer class.

In addition, there are also a number of other features of electric tariffs incorporated in the rate structure which includes the relationship and form of prices within particular customer classes. The tariff structure is set to maintain equity between and within customer classes, ensuring that there is no discrimination against or preferential treatment of any particular customer group. Some of the factors considered in the tariff structure are:

• season of use,

• time of use,

• quantity of energy used,

• whether increased consumption is encouraged, discouraged, or considered neutr

• social aspects such as the desire for a lifeline rate for low–income or elderly customers, known as public service obligations (PSOs).

Table 6.1: Generalized breakdown of electric tariff schedule components
Customer class

Comments

Energy

Demand

Power

factor

(kWh)

(kW)

(kVar)

Residential

Small user but

large numbers

of them

+

Commercial

Small to moderate

user, relatively large

numbers

+

Small industrial

Small to moderate

user, fewer

customers

+

+

Large industrial

Large user with low

priority, typically, only

a few customers in this

class, but they consume

a large percentage of

the electricity produced

+

+

+

6.2.3

Residential tariff structures

A typical residential bill includes:

• an administrative customer charge,

• an energy charge which is large enough to cover both the actual energy charge and an implicit demand charge, and

• a fuel adjustment charge.

Residential rates do not usually include an explicit demand charge because the individual demand is relatively inconsequential and expensive to meter.

The three main types of residential tariff structures are:

• Standard residential rate schedule,

• Low–use residential rate schedule,

• Residential rate schedules to control peak uses.

A typical monthly standard residential tariff schedule for a residential customer c

(i) Customer charge, e.g., 8.00e/month,

(ii) Energy charge, e.g., all kWh at 6.972ec/kWh,
(iii) Fuel adjustment, e.g., a rather complex formula is used to calculate the fuel adjustment charge each month.

A typical monthly low–use residential tariff schedule for a residential customer consist of:

(i) Customer charge, e.g., 5.45e/month,

(ii) Energy charge, e.g., all kWh at 5.845ec/kWh,
(iii) Fuel adjustment, e.g., a rather complex formula is used to calculate the fuel adjustment charge each month.

This tariff, which is an attempt to meet the needs of those on fixed incomes, is used for customers whose monthly consumption never exceeds 500kWh. In

addition, it cannot exceed 400kWh more than twice a year.

6.2.4 Residential tariff schedules to control peak uses

Although individual residential demand is small, collectively residential users place a peak demand burden on the utility system because the majority of them use their electricity at the same times of the day during the same months of the year. Some utilities introduced the residential tariff schedules to control peak uses by charging more for energy during peaking months in an attempt to solve this problem. Many utilities have an optional time–of–day or time–of–use tariff which is supposed to help alleviate the daily peaking problem by charging customers more for electric use during these peak periods. A number of utilities also have a load management program to control customers' appliances.

Generally, the daily load demand curve experiences one large peak around 9:00 a.m. and another somewhat smaller peak near 9:00 p.m. The first peak occurs when people get up in the morning and start using electricity. They all turn up their electric heat, cook breakfast, take a shower, and dry their hair at about the same time on weekday mornings. Then in the evening, they all come home from work, start cooking dinner, turn the heat back up (or use it more because nights are colder) and turn on the TV set at about the same time.

Seasonal use tariff schedule: A typical residential tariff schedule where the season of use is a factor in the tariff structure consists of:

(i) Customer charge, e.g., 6.50e/month,

(ii) Energy charge, e.g., on–peak season (June through October) all kWh at 7.728ec/kWh, off–peak season (November through May) first 600kWh at 7.728ec/kWh, all additional kWh at 3.898ec/kWh,

(iii) Fuel adjustment, e.g., a rather complex formula is used to calculate

the fuel adjustment charge each month.

The above tariff is chosen to attack the residential peaking problem by charging more for electricity consumed in the summer months when the highest peaks occur. During the summer peak season a constant charge or flat tariff is used for all energy (7.728ec/kWh) regardless of the amount consumed. In the off–peak season, however, the utility uses a declining block approach and charges a higher rate for the first 600kWh of energy than it does for the remaining kWh use.

Time–of–day or time–of–
use pricing: To handle the daily peaking problem, some tariffs charge more for en

This requires the utility to install relatively sophisticated meters. It also requires some customer habit changes. Time–of–
use pricing for residential customers is not very popular today, however, most util
required by their energy regulatory agencies to provide a time–of–use tariffs for customers who desire one, so some utilities have some form of time–of–use pricing. A sample time–of–
day tariff structure for residential customers consists of:

(i) Customer charge, e.g., 16.00e/month,

(ii) Energy charge, e.g., on–peak energy at 10.857ec/kWh, off–peak energy at 5.800ec/kWh (on–peak hours: (a) November through March, Monday through Friday, 6:00 a.m.

to 10:00 a.m.

and

6:00 p.m. to 10:00 p.m. and (b) April through October, Monday through Friday, 1
peak hours: all other hours),

(iii) Fuel adjustment, e.g., a rather complex formula is used to calculate the fuel adjustment charge each month.

Peak shaving: Some utilities offer a discount to residential customers if the utility can hook up a remote control unit to cycle large electricity using appliances in the home (usually electric heaters, air conditioners and water heaters). This utility load control program is also called load management. This way the utility can cycle large appliance loads on and off periodically to help reduce demand. Since the cycling is performed over s no discomfort. This approach is rapidly gaining in popularity. A sample load management tariff for residential customers consists of:
(i) Customer charge, e.g., 9.00e/month,

(ii) Energy charge, e.g., first 1000kWh at 8.250ec/kWh, over 1000kWh at 9.300ec/kWh

(iii) Load management credit per month: Credit will be applied to the bill of all customers with load management switches who use 500

kWh or more per month as follows:

• Electric water heater controlled January–December: e4.00

• Electric central heating controlled October–March for 5 to 7.5

minutes of each 25–minute period: e3.00

• Electric central air conditioner controlled April–September for 5 to 7.5 minutes of each 25–minute period: e3.00

• Electric central heating controlled October–March for 12.5 minutes of each 25–minute period: e8.00

• Electric central air conditioner controlled April–September for 5 to 7.5 minutes of each 25–minute period: e8.00

(iv) Fuel adjustment, e.g., a rather complex formula is used to calculate the fuel adjustment charge each month.

This tariff provides a rebate to customers who agree to allow the utility to turn off their electric water heaters or air conditioners for short periods of time during peak hours. Such tariff also includes an inclining block feature.

6.2.5 Commercial tariff structures

Simple commercial tariff schedules usually involve only energy (kWh) charges and customer charges. Sometimes, demand (kW) charges are used requiring a demand meter. The energy charge for commercial customer class is often substantially higher than for residential users, e.g., one tariff schedule charges almost 8ec/kWh for commercial users during peak season but only a little more than 5ec/kWh for residential users during the same season. This difference i

- many businesses have widely varying loads depending on the health of the economy,

- many businesses close after only a few months of operation, sometimes leaving large unpaid bills,

- some regulatory agencies feel that residential customers should have lower tariffs since they cannot pass on electric costs to someone else.

6.2.6 Small industrial tariff structures

The small industrial tariff often becomes more complex because of the nature of the equipment used in the industry, and their consumption tends to be higher. Consequently, the billing becomes more sophisticated. Usually, the same cost categories occur as in the simpler schedules, but other categories are added. Some of these are outlined below.

Voltage level

One degree of complexity is introduced according to what voltage level the custo
voltage levels and do the necessary transforming to usable levels on–site, then the utility saves considerable expense and can charge less. If the customer needs the service at a lower voltage, then the utility must install transformers

and maintain them. In that case, the cost of service goes up and so does the bill.

The voltage level charge can be handled in the tariff schedule in several ways. One is for the utility to offer a percentage discount on the electric bill if the customer owns its own primary transformer and accepts service at a higher voltage than it needs to run its equipment. Another is to increase the energy charge as the voltage level decreases. Installing their own transformers
cutting opportunity for industrial users and
should be explored. Maintaining transformers is a relatively simple (though potentially dangerous) task, but the customer may also need to install standby transformers to avoid costly shutdowns.

Demand billing

Understanding industrial rate structures means understanding the concept of demand billing. Consider Figures 6.1 and 6.2 where energy demands on a utility are plotted against time for two hypothetical companies. Since the instantaneous demand (kW) is plotted over time, the integration of this curve (i.e., the area under the curve) is the total energy (kWh) consumed (see shaded area). Company B and Company A have the same average demand, so the total energy consumed by B equals that of A. Company B's peak demand and its average demand are the same, but Company A has a seasonal peak that is almost twice as high as its average demand. Because the kWh consumed by each are equal, their bills for energy consumption will be equal, but this seems unfair.

Company B has a very flat demand structure so the utility can gear up for that level of service with high–efficiency equipment. Company A, however, requires the utility to supply about twice the capacity that company B needs but only for one short period of time during the year. This means the utility

must maintain and gear up equipment which will only be needed for a short period of time. This is quite expensive, and some mechanism must be used by the utility to recover these additional costs.

To properly charge for this disproportionate use of facilities and to encourage con charge industrial users for the peak demand incurred during a billing cycle, normally a month. Often a customer can achieve substantial cost reductions simply by reducing peak demand and still consuming the same amount of elec-

tricity. A good example of this would be to move the use of an electric furnace from peaking times to non–peaking times (maybe second or third shifts). This means the same energy could be used at less cost since the demand is reduced.

)W

annual average demand

(M

and

emD

Time (1 year)

Figure 6.1: Demand profile for hypothetical company A Ratchet clause

Many utility tariff structures have a ratchet clause associated with their demand c realize that if the utility must supply power to meet a peak load in July, it must keep that equipment on hand and maintain it for the next peak load which may not occur for another year. To charge for this cost, and to encourage c have a ratchet clause.

A ratchet clause usually says that the billed demand for any month is a percentage (usually greater than 50%) of the highest maximum demand of the previous 11 months or the actual demand, whichever is greater. The demand is normally corrected for the power factor. For a company with a large seasonal

)W

annual average demand

(M

and

emD

Time (1 year)

Figure 6.2: Demand profile for hypothetical company B

peaking nature, this can be a real problem. A peak can be set in July during a heavy air conditioning period that the company in effect pays for a full year.

The impact of ratchet clauses can be significant, but often a company never realizes this has occurred.

Power factor

Power factor is a complex subject to explain, but it can be a vitally important element in a company's electrical bill. For example a company with low power factor of 51% means paying a penalty of 56.9% on demand billing. With the addition of power factor correction capacitors, this penalty could have been avoided or minimized.

The power factor is important because it imposes costs on a utility that are not recovered with demand and energy charges. Industrial customers are more likely to be charged for a poor power factor. They create greater power factor problems for a utility because of the equipment they use. They are also more likely to be able to correct the problem. In order to understand the power factor, understanding electric current theory is important. The cur-

rent required by induction motors, transformers, fluorescent lights, induction heating furnaces, resistance welders, etc., is made up of three types of current:
Current producing real power: Also known as working current or power producing current. This is the current which is converted by the equipment into u
working current is the kilowatt (kW).

Current producing reactive power: Also known as magnetizing current or watt–less current. This is the current which is required to produce the

magnetic flux necessary for the operation of induction devices. Without magnetiz transformer or across the air gap of an induction motor. The unit of measurement of the reactive power associated with magnetizing current is the kilovar (kVar).

Current producing apparent power: Also known as total current or total power current. This is the current that is read on an ammeter in the circuit. It is made up of the vector sum of the magnetizing current and the power–producing current. The unit of measurement of apparent power associated with this total current is the kilovoltampere (kVA).

Power factor is the ratio of real power being used in a circuit, expressed in kW, to the apparent power drawn from the power line, expressed in kVA. The relationship of kW, kVar, and kVA in an electrical system can be illustrated by scaling vectors to represent the magnitude of each quantity, with the vector for kVar at a right angle to that for kW. When these components are added vectorially, the resultant is the kVA vector. The angle between the kW and kVA vectors is known as the phase angle. The cosine of this angle is the power factor.

Unless some way of billing for a low power factor is incorporated into a tariff schedule, a company with a low power factor would be billed the same as a company with a high power factor. Most utilities do build in a power factor penalty for industrial users. However, the way of billing varies widely.

Some of the more common ways include:

- Billing demand is measured in kVA instead of kW. As the power factor is improved, kVA is reduced, providing a motivation for power factor improvement.

- Billing demand is modified by a measure of the power factor. Some utilities will increase billed demand one percent for each one percent the power factor is below a designated base. Others will modify demand as follows:

Billed Demand = Actual M etered Demand × Base Power Factor
Actual P ower F actor

This way, if the actual power factor is lower than the base power factor, the billed demand is increased. If the actual power factor is higher than the base power factor, some utilities will allow the fraction to stay, thereby providing a reward instead of a penalty. Some will run the calculation only if actual power factor is below base power factor.

• The demand or consumption billing schedule is changed according to the power factor. Some utilities will change the schedule for both demand and consumption according to the power factor.

• A charge per kVar is used. Some companies will charge for each kVar used above a set minimum. This is direct billing for the power factor.

In addition, since a regular kW meter does not recognize the reactive power, some other measuring instrument must be used to determine the reactive p or the utility might decide to only periodically check the power factor at a facility. In this case a utility would send a crew to the facility to measure the power factor for a short period of time, and then remove the test meter.

Or, many utilities would just install an electronic meter with remote reading agility.

6.2.7

Large industrial tariff structures

Most utilities have very few customers that would qualify for or desire to be on a large industrial tariff schedule. Sometimes, however, one or two large industries will utilize a significant portion of a utility’s total generating capacity. T conceived and well–designed tariff schedule is necessary.

Typically a large industrial schedule will include the same components as a small industrial schedule. The difference occurs in the amount charged

for each category. The customer charge, if there is one, tends to be higher.

The minimum kW of demand tends to be much higher in cost/kW, but all additional kW may be somewhat lower (per kW) than on small industrial tariff schedules.

Similarly, the charge per kWh for consumption can be somewhat less. The reason for this is economy of scale since it is cheaper for a utility to deliver a given amount of electrical energy to one large customer than the same amount of energy to many smaller customers.

6.3

Natural gas tariff structures

Natural gas tariff schedules are similar in structure to electric rate schedules, but they are often much simpler. Natural gas companies also experience a peaking problem. Such peaking problems are likely to occur on very cold winter days and/or when supply disruptions exist. Due to the unpredictable nature of these peak problems, gas utilities normally do not charge for peak demand. Instead, customers are placed into interruptible priority classes.

A customer with a high priority will not be curtailed or interrupted unless absolutely necessary. A customer with the lowest priority, however, will be curtailed or interrupted whenever a shortage exists. Normally some gas is supplied to keep customer’s pipes from freezing and pilot lights burning. To encourage use of the low–priority tariff schedules, utilities charge significantly less for this gas rate. Most gas utilities have three or four priority levels.

Some utilities allow customers to choose their own tariff schedule, while others strictly limit the choice.

Below sample tariff schedules for four priority levels are provided with summer periods including the months from May through October and winter periods including the months from November through April:
Residential: Priority 1

- Winter:

– First 1Btu/month: e5.120

– Next 2.9MMBtu/month: 5.347e/MMBtu

– Next 7.0MMBtu/month: 3.530e/MMBtu

– Over 10MMBtu/month: 3.725e/MMBtu

• Summer:

– First 1Btu/month: e5.120

– Next 2.9MMBtu/month: 5.347e/MMBtu

– Over 3.0MMBtu/month: 3.530e/MMBtu

Commercial: Priority 2

• Winter:

– First 1Btu/month: e6.790

– Next 2.9MMBtu/month: 5.734e/MMBtu

– Next 7.0MMBtu/month: 5.386e/MMBtu

– Next 90MMBtu/month: 4.372e/MMBtu

– Next 1900MMBtu/month: 4.127e/MMBtu

– Next 6000MMBtu/month: 3.808e/MMBtu

– Over 8000MMBtu/month: 3.762e/MMBtu

• Summer:

– First 1Btu/month: e6.790

– Next 2.9MMBtu/month: 5.734e/MMBtu

– Next 7.0MMBtu/month: 5.386e/MMBtu

– Next 90MMBtu/month: 4.372e/MMBtu

– Next 100MMBtu/month: 4.127e/MMBtu

– Next 7800MMBtu/month: 3.445e/MMBtu

– Over 8000MMBtu/month: 3.399e/MMBtu

Industrial: Priority 3

• Second Interruptible:

– First 1Btu/month: e19.040

– Next 2.9MMBtu/month: 5.490e/MMBtu

– Next 7.0MMBtu/month: 5.386e/MMBtu

– Next 90MMBtu/month: 4.372e/MMBtu

– Next 100MMBtu/month: 4.127e/MMBtu

– Next 7800MMBtu/month: 3.445e/MMBtu

– Over 8000MMBtu/month: 3.399e/MMBtu

Industrial: Priority 4

• First Interruptible:

– First 4000MMBtu/month or fraction thereof: e12,814.00

– Next 4000MMBtu/month: 3.168e/MMBtu

– Over 8000MMBtu/month: 3.122e/MMBtu

Based on the above tariff schedules the industrial customer is limited in choice to priorities 3 and 4. Some points are demonstrated in this collection of schedules. First, the energy costs decrease as the priority goes down, but the probability of a curtailment or interruption dramatically increases. Second, the winter residential rate has an increasing block component on the block of gas use over 10MMBtu/month. Only very large residential consumers would approach this block, so its intent is to discourage wanton utilization. Like electric tariffs, fuel cost adjustments do exist in gas tariffs. Sales taxes also apply to natural gas bills. Again, some countries do not charge sales tax on gas used directly in production. As is the case with electricity tariffs, natural gas tariffs differ significantly in different parts of the world.

Fundamentals of Energy Regulation

Chapter 7

RES Technologies for Power

Generation

Renewable energy sources (RES) use domestic resources that have the potential t
pollutants and greenhouse gases. RES technologies tap naturally occurring flows of energy to produce electricity, fuel, heat, or a combination of these energy
and have less impact on the environment than conventional sources.

They can provide a reliable source of energy at a stable price. RES technologies a
fossil energy sources such as, wind, solar,
geothermal, wave, tidal, hydropower and biomass. A general description of the currently available RES technologies, such as, wind, concentrated solar power (CSP), photovoltaics (PVs), biomass, geothermal, hydropower, tidal and wave is provided below.

7.1

Wind turbine technology

Large, modern wind turbines operate together in wind farms to produce electricit
localized energy needs. Wind turbines capture energy by using propeller–like
blades that are mounted on a rotor. These blades are placed on top of high
towers, in order to take advantage of the stronger winds at 30 meters or more
above the ground. The wind causes the propellers to turn, which then turn

the attached shaft to generate electricity. Wind can be used as a stand–alone source of energy or in conjunction with other RES systems. There are many onshore wind farms around the world. Offshore wind farms in coastal waters are being developed because winds are often stronger blowing across the sea.

The first wind turbines for electricity generation had already been developed at th
step by step since the early 1970s. By the end of the 1990s, wind energy has re–emerged as one of the most important sustainable energy resources. During the last decade of the twentieth century, worldwide wind capacity has doubled approximately every three years. Costs of electricity from wind power have fallen to about one–
sixth since the early 1980s. And the trend seems to continue. It is predicted that tl
by about 25% per year until 2010 and cost will be dropping by an additional 20% to 40% during the same time period.

Wind energy technology itself also moved very fast towards new dimensions. At
a rotor diameter of around 70 meters are available from many manufacturers.

The first demonstration projects using 2MWe wind turbines with a rotor diameter
commercially available. Currently, in operation are 7MWe wind turbines.

Horizontal–axis, three–bladed, medium to large size grid–connected wind turbines with a capacity greater than 100kWe have, currently, the largest market s

Three–
bladed wind turbines have the advantage that the rotor moment of inertia is easier
moment of inertia of a two–bladed turbine. Furthermore, three–bladed wind turbines are often attributed better visual aesthetics and a lower noise level

than two–bladed wind turbines. Both aspects are important considerations for wind turbine utilization in highly populated areas.

Wind turbines reach the highest efficiency at the designed wind speed, which is usually between 12m/s to 16m/s. At this wind speed, the power output reaches the rated capacity. Above this wind speed, the power output of the rotor must be limited to keep the power output close to the rated capacity and thereby reduce the driving forces on the individual rotor blade as well as the load on the whole wind turbine structure.

Currently, three options for the power output control are currently used

which are the stall, pitch and active stall regulation. The wind energy advantages

- no fuel is used,
- no wastes or greenhouse gases are produced,
- the land beneath can usually still be used for farming,
- can supply energy to remote areas and
- maintenance requirements are minimal.

The wind energy disadvantages can be summarized as:

- the wind is not always predictable (e.g., some days have no wind),
- some people feel that covering the landscape with these towers is un-sightly,
- can kill birds since migrating flocks tend to like strong winds,
- can affect nearby houses television reception,
- can be noisy since wind generators have a reputation for making a constant, low

• suitable areas for wind farms are often near the coast, where land is expensive.

Current research and development in the field of wind technologies include:

• the reduction of wind turbine weight,

• the reduction of noise,

• the development of methodologies for short term wind power forecasting,

• the utilization of low wind potential locations and

• the reduction in the kWh cost.

7.2

CSP technology

Current CSP technologies are distinguished in the way they concentrate solar radiation, such as:

(a) parabolic trough systems,

(b) solar tower systems, and

(c) solar dish systems.

The direct solar radiation is concentrated using reflectors and the energy concentr

7.2.1

Parabolic Trough

A parabolic trough, which is the most common available CSP technology, is a long, trough–shaped reflector with a parabolic cross–section. As a result

of this cross–section, sunlight reflected within the trough is focused along a line running the length of the trough. In order to collect this heat, a pipe is positioned along the length of the trough at its focus and a heat collection fluid is pumped through it. The tube (or receiver) is designed to be able to absorb most of the energy focused onto it and must be able to withstand the resultant high temperature. Typical receivers for this purpose are made of steel tubing with a black coating and surrounded by a protective glass cover with the space between the two evacuated to reduce heat loss. An anti–reflective coating may be added to the outer glass surface to increase efficiency further.

The solar array of a parabolic trough power plant consists of several parallel rows of parabolic reflectors. The heat collecting fluid which is pumped through the pipes along the length of each solar trough is typically synthetic oil, similar to engine oil, capable of operating at high temperature. During operation it is likely to reach between 300oC and 400oC. After circulating through the receivers the oil is passed through a heat exchanger where the heat it contains is extracted to raise steam in a separate sealed system and the steam is then used to drive a steam turbine generator to produce electricity. The heat collecting fluid is then cycled back through the solar collector field to collect more heat.

The parabolic troughs along which these tubular receivers run may be five to six meters wide, one or two meters deep and up to 150m in length (though

an individual trough of this length will usually be constructed from modular sections). Many of these are required to collect sufficient energy to provide heat for a single power plant. As a consequence, these solar troughs form a physically large part of the solar plant and their cost can have a significant impact on plant economics.

Parabolic solar troughs are usually aligned with their long axes north south and they are mounted on supports that allow them to track the sun from east to west across the sky. These supports may be made of steel or aluminum.

In the first commercial plants the actual mirrors were made from 4mm glass which is both heavy and expensive. Modern developments aim to reduce the

cost and weight by using new techniques and materials including polished aluminum instead of coated glass mirrors. Energy conversion efficiency is one of the keys to commercial success for solar thermal plants. The reflecting mirrors must be both accurately shaped, and accurately positioned in order to achieve maximum solar collection efficiency. Then the tracking system must ensure that each trough is in the optimum position, all day. Finally the tubular energy receivers must operate at the highest efficiency possible too.

7.2.2

Solar towers

Solar towers (often called solar central receiver power plants) offer an alternative plant. In this case the collector field consists of an array of heliostats (mirrors) at the centre of which is a tower. At the top of the tower is a receiver designed to collect the heat from the sun.

In operation each heliostat has an individual tracking system and all are aligned so that the sunlight striking them is directed onto the receiver atop the central tower. As the sun moves across the sky, each mirror must be moved too if high collection efficiency is to be maintained. The receiver itself is designed to absorb the energy from the sunlight incident upon it and transfer it to a heat transfer fluid. Depending on system design, this heat transfer may be water, molten salt or air. Solar towers are normally designed with energy storage capability so that they can, in principle, operate 24 hours a day.

7.2.3

Solar dishes

A solar dish power plant uses a circular parabolic dish to collect solar radiation and bring it to a focus. A heat engine situated at the focus exploits the heat

generated by this concentration to provide mechanical motion which drives a generator. In the case of the solar dish, the heat engine is normally a special

type of engine called a Stirling engine which has extremely high efficiency.

There have also been attempts to use small gas turbines based on the Brayton cycle[1].

Typical dishes are between five and ten meters in diameter and with reflective are

Material limitations are likely to restrict the practical size of dishes though dishes up to 15m in diameter (700m2) have been proposed.

Dishes in this size range could provide up to 50kWe of power. However, today Stirling engines are limited to 25kWe. These are best matched with smaller dishes. Gas turbine heat engines based on micro turbines can provide higher output but they are significantly less efficient that Stirling engines.

Both micro gas turbine and Stirling engine–based systems can be designed for hybrid operation using a combination of solar heat and the heat from combustion of natural gas.

As with both parabolic trough collectors and the heliostats for solar tower power plants, solar dishes have to be able to track the sun across the sky in order to achieve maximum efficiency. Tracking systems tend to be expensive and this means that the cost of the dish plays a significant role in the economics of the power system. The dish support is usually constructed as a lattice upon which individual curved mirrors are mounted to create the overall dish.

These mirrors may be of glass or polished metal, circular or rectilinear. At the centre of the dish there is a projecting beam to which the heat engine is attached, positioned so as to capture the heat concentrated at the focus of the dish. Dishes with Stirling engines have been built in sizes ranging from 5kWe to 25kWe. These engines are in theory capable of 40% energy conversion efficiency although practical engines today achieve closer to 30%.

7.2.4

Thermal storage

The molten salt system, used for thermal storage in solar thermal power plants, is typically a mixture of sodium and potassium nitrates which melts at about 220oC. In operation the salt is stored in a tank maintained at about 300oC.

Molten salt is taken from this tank and passed through the high temperature receiver where it absorbs heat provided by the mirrors from the collector field
1The thermodynamic cycle upon which the gas turbine is based.

and is then returned to a high temperature storage tank at a temperature of around 550oC. At this temperature the salt can act as a source of high–

grade heat and it appears possible to operate with even higher temperatures if necessary.

Electricity is generated by taking molten salt from the hot storage tank and passing it through a heat exchanger where the heat it contains is transferred to water, generating steam to drive a steam turbine. The cooled molten salt is then returned to the cold storage tank ready to pass through the solar energy receiver once more. By careful sizing of a plant of this type it is quite feasible to build a power station capable of providing power throughout the day and night.

The CSP technology advantages can be summarized as:

• no fuel is used,

• no wastes or greenhouse gases are produced, and

• electricity is produced during peak load demand periods.

The CSP technology disadvantages can be summarized as:

• requirement of large land areas, and

• high capital cost.

Current research and development in the field of CSP technology includes:

• the improvement of the solar field efficiency, and

• the reduction of electricity generation cost.

7.3 The PV technology

PV systems convert energy from the sun directly into electricity. They are composed of photovoltaic cells, usually a thin wafer or strip of semiconductor material that generates a small current when sunlight strikes them. Multiple cells can be assembled into modules that can be wired in an array of any size. Small photovoltaic arrays are found in wristwatches and calculators, the largest arrays have capacities in excess of 30MWe.

Solar electricity produced by PV solar cells is one of the most promising options yet identified for sustainably providing the world's future energy requirer silicon wafers as used in microelectronics, a transition is in progress to a second generation of a potentially much lower–cost thin–
film technology. Cost reductions from both increased manufacturing volume and decades to a level where the cells can provide competitively priced electricity on a large scale.

The choice of the semiconductor defines the PV technology. There are two main PV technologies:

(a) Crystalline silicon solar cells,

(b) Thin–film solar cells.

The technology used to make most of the crystalline silicon solar cells, fabricated so far, borrows heavily from the microelectronics industry and is known as silicon wafer technology. The silicon source material is extracted from quartz, although sand would also be a suitable material. The silicon is then refined to very high purity and melted. From the melt, a large cylindrical single crystal is drawn. The crystal, or ingot, is then sliced into circular wafers,

less than 0.5mm thick, like slicing bread from a loaf.

Sometimes this cylindrical ingot is squared–off before slicing so the wafers have a quasi–square shape that allows processed cells to be stacked more closely side–by–side. Most of this technology is identical to that used in the much larger microelectronics industry, benefiting from the corresponding eco quality than that used in microelectronics, additional economies are obtained by using off–specification silicon and off–specification silicon wafers from this industry.

The first step in processing a wafer into a cell is to etch the wafer surface with chemicals to remove damage from the slicing step. The surface of crystallin rates in different directions through the silicon crystal. This leaves features on the surface, with the silicon structure that remains determined by crystal directio n junction is then formed. The impurity required to give p–type properties (usually boron) is introduced during crystal

growth, so it is already in the wafer. The n–type impurity (usually phosphorus) is now allowed to seep into the wafer surface presence of a phosphorus source.

Crystalline silicon solar cells hold 93% of the market. Despite the fact that it is a relatively poor light absorbing semiconducting material, over the years it has been the primary raw material used in most solar PV cells due to its ability to yield stable and efficient cells, with efficiencies between 11–16% in terms of converting sunlight energy to electrical energy.

There are two types of crystalline silicon solar cells that are used in the industry:

(a) Monocrystalline silicon cells (single Si),
(b) Multicrystalline silicon cells (multi–Si or poly–Si).

The monocrystalline silicon cell is made using cells saw-cut from a single cylindrical crystal of silicon. The main advantage of the monoc is the high efficiency which is around 15%. The multicrystalline silicon cell is

made by sawing a cast block of silicon first into bars and then into wafers. Multic
to the simpler manufacturing process. However they are slightly less efficient than the monocrystalline with average efficiency of approximately 12%.

In general crystalline silicon solar cells have a relatively high production cost and subsequently high selling price. Moreover, its dependence on purified silicon as the key raw material creates additional difficulty since there is global shortage of the material. The relative high costs result from the complex and numerous production steps involved in wafer and cell manufacturing and the large amount of highly purified silicon feedstock required. Due to the high production cost of the crystalline silicon wafers, the PV industry has been seeking for alternative ways of manufacturing PV solar cells using cheaper materials such as the thin–film solar cells.

In the thin–
film technology approach, thin layers of semiconductor material are deposited on
sheet of glass. Typically, less than a micron (μm) thickness of semiconductor material is required, 100–1000 times less than the thickness of silicon wafer.

Reduced material use with associated reduced costs is a key advantage. Another a
small silicon wafer, becomes much larger, for example, as large as a conveniently

Silicon is one of the few semiconductors inexpensive enough to be used to make solar cells from self–supporting wafers. However, in thin–film form, due to the reduced material requirements, virtually any semiconductor can be used. Since semiconductors can be formed not only by elemental atoms, such as silicon, but also from compounds and alloys involving multiple elements, there is essentially an infinite number of semiconductors from which to choose.

At present, solar cells made from different thin–film technologies are either available commercially, or close to being so, such as:

• cadmium telluride (CdTe),

• copper indium diselenide (CIS),

• amorphous silicon (a–Si),

• thin–film silicon (thin film–Si).

Amorphous silicon is in commercial production while the other three technologie above technologies is expected to establish its superiority and attract investment i on cell prices. As each of these thin–film technologies has its own strengths and weaknesses, the likely outcome is not clear at present.

Thin–film panels have several important drawbacks. What they gain in cost savings and flexibility they lose in efficiency resulting in the lowest efficienc 7%. The main interest in these technologies rises from the fact that they can be m relatively inexpensive industrial processes, in comparison to crystalline silicon technologies yet they offer typically higher module efficiency than amorphous silicon.

In addition to the above main PV technologies concentrating PVs (CPVs) have smaller area than the other types of PV cells. In this technology, the sunlight is focused on a photovoltaic cell, which is located at the focus point, by the use of large area of lenses or mirrors and a single or two axis tracking system to follow the sun. The use of concentrating solar cells reduces the usage of silicon semiconducting material, increasing the sunlight concentration ratio, improves the performance of general PV materials and also allows for the use of high performance materials such as Gallium Arsenide (GaAs). The photovoltaics advantages can be summarized as:

• no fuel is used,

• complementarily with other energy sources, both conventional and renewable,

• flexibility in terms of implementation since PV systems can be integrated into buildings, installed as separate mobile or non-mobile modules, or in central electricity generating stations,

- no wastes or greenhouse gases are produced, and
- no moving parts, therefore, almost no maintenance.

The photovoltaics disadvantages can be summarized as:

- low efficiency (around 14%), and
- high capital cost.

Current research and development in the field of photovoltaics includes:

- the improvement of the efficiency to reach 25%,
- the reduction of electricity generation,
- the increase of the technical lifetime to reach 40 years, and
- the development of advance balancing and storage technologies for large scale implementation of PVs.

7.4

Biomass energy

Biomass covers a wide range of products, by–products and waste streams from forestry and agriculture (including animal husbandry) as well as municipal a biodegradable fraction of products, waste and residues from agriculture (includin well as the biodegradable fraction of industrial and municipal waste. Biomass thus includes trees, arable crops, algae and other plants, agricultural and forest re products and the
organic fraction of municipal solid waste. There are three ways to use biomass:

(a) It can be burned to produce heat and electricity, (b) It can be changed to gas–like fuels, such as methane, hydrogen, and carbon monoxide,

(c) It can be changed to a liquid fuel.

Liquid fuels, also called bio–fuels, include mainly two forms of alcohol: ethanol and methanol. The two most common bio–fuels are:

- ethanol, and
- bio–diesel.

The most commonly used bio–fuel is ethanol, which is produced from sugar-cane, corn, and other grains. A blend of gasoline and ethanol is already used in cities with high air pollution.

However, ethanol made from biomass is currently more expensive than gasoline on a gallon–for–
gallon basis. Ethanol is mostly used as a fuel additive or oxygenate to enhance th monoxide and other smog–causing emissions. So, it is very important for scientists to find less expensive ways to produce ethanol from other biomass crops.

Bio–diesel can be used as a diesel additive to reduce vehicle emissions or

in its pure form to fuel a vehicle. Concerns about the depletion of diesel fuel reserves and the pollution caused by continuously increasing energy demands make bio–diesel an attractive alternative motor fuel for compression ignition engines.

Heat is used to convert biomass into a fuel oil, which is then burned like petroleum to generate electricity. Biomass can also be burned directly to produce alized countries, the main biomass processes utilized in the future are expected to be the direct combustion of residues and wastes for electricity generation.

The future of biomass electricity generation lies in biomass integrated gasificatio energy conversion efficiencies.

The electricity is produced by the direct combustion of biomass; advanced gasification and pyrolysis technologies are almost ready for commercial–scale use.

Biomass power plants use technology that is very similar to that used in coal–fired power plants. The biomass advantages can be summarized as:

• waste materials are used,

• the fuel, in some cases, tends to be cheap, and

• less demand on the Earth's resources.

The biomass disadvantages can be summarized as:

• collecting the waste in sufficient quantities can be difficult,

• fuel is burned, so greenhouse gases are emitted, and

• some waste materials are not available all year round.

Current research and development in the field of biomass includes:

- the improvement of the various technologies efficiency,
- the development of reliable and cost effective gasification systems,
- the development of new methods for cost effective production of clean bio–fuels for use in combustion engines and fuel cells, and
- the reduction of costs.

7.5 Geothermal energy

The interior of the Earth is hot. The temperature in the Earth increases gradually with depth and reaches 4500oC at the center of the Earth. In general, th exceptional locations, hot rocks at a temperature of several hundred degrees are found at a depth of just a few kilometers. Hot springs, steam vents, and geysers bring some of the heat from the interior of the Earth to the surface.

These natural sources of geothermal energy are being exploited in a few places such as near Pisa in Italy, the Geysers in California, Cerro Prieto in Mexico, and Wairakei in New Zealand. The geothermal power plants operate with steam blowing out from wells drilled down to depths of as much as 2100m.

Geothermal sources near populated areas can be used directly to provide heat and steam for homes and for industrial processes. In Iceland, nearly half the population lives in houses heated by geothermal sources, almost all the houses in Reykjavik are heated in this manner.

The direct application of geothermal energy can involve a wide variety of end uses, such as space heating and cooling, industry, greenhouses, fish farming, and health spas. It uses mostly existing technology and straightforward e acceptability of the direct use of geothermal energy have been demonstrated throughout the world.

Electricity is produced with geothermal steam in 21 countries spread over
all continents.

Low–temperature geothermal energy is exploited in many
countries to generate heat, with an estimated capacity of about 10000MWth.

Geothermal energy is clean, cheap and renewable, and can be utilized in various f
dry–ice production process, heat pumps, greenhouse heating, swimming and
balneology (therapeutic baths), industrial processes, and electricity generation. Th

• no fuel is used,

• no wastes or greenhouse gases are produced, and

• less space is required.

The geothermal energy disadvantages can be summarized as:

• no many places around the world in which geothermal potential is available,

• sometimes a geothermal site may "run out of steam", perhaps for decades, and

• hazardous gases and minerals may come up from underground, and can
be difficult to safely dispose of.

7.6

Hydropower

Hydropower (also called hydroelectric power) facilities in the world can generate
and streams can be captured and turned into hydropower. Hydropower is also
inexpensive, and like many other renewable energy sources, it does not produce a

that will not only help maximize the use of hydropower, but also minimize
adverse environmental effects. A variety of mitigation techniques are in use
now, and environmentally friendly turbines are under development.

Large–scale hydropower provides about one–quarter of the world's total electricity supply, virtually all of Norway's electricity, and more than 40%

of the electricity used in developing countries. The technically usable world potential of large–scale hydro is estimated to be over 2200GWe, of which only about 25% is currently exploited. There are two small–scale hydropower systems, such as, microhydropower systems, with capacities below 100kWe, and small hydropower systems, with a capacity between 101kWe and 1MWe.

Large–
scale hydropower supplies 20% of global electricity. In developing countries, con
financial, environmental, and social constraints.

For a hydroelectric power plant a dam is built to trap water, usually in a valley where there is an existing lake. Water is then allowed to flow through tunnels in the dam, to turn turbines and thus drive generators. The dam is much thicker at the bottom than at the top, because the pressure of the water increases with depth. Although there are many suitable sites around the world, hydro–electric dams are very expensive to build. However, once the station is built, the water comes free of charge and there is no waste or pollution. The hydropower advantages can be summarized as:

• no fuel is used,

• no wastes or greenhouse gases are produced,

• much more reliable than wind or solar or wave power,

• water can be stored above the dam ready to cope with peaks in demand,

• hydro–electric power stations can increase to full power very quickly, unlike other power stations, and

• electricity can be generated constantly.

The hydropower disadvantages can be summarized as:

• the dams are very expensive to build, however, many dams are also used for flood control or irrigation, so building costs can be shared,

• building a large dam will flood a very large area upstream, causing problems fo

• finding a suitable site can be difficult (the impact on residents and the environment may be unacceptable), and

• water quality and quantity downstream can be affected, which can have an impact on plant life.

7.7 Tidal energy

Tides are caused by the gravitational attraction of the moon and the sun acting upon the oceans of the rotating earth. The relative motions of these bodies cause the surface of the oceans to be raised and lowered periodically, according to a number of interacting cycles. These include:
a half day cycle, due to the rotation of the earth within the gravitational field of the moon,

a 14 day cycle, resulting from the gravitational field of the moon combining with that of the sun to give alternating spring (maximum) and neap (minimum) tides,

a half year cycle, due to the inclination of the moon's orbit to that of the earth, giving rise to maxima in the spring tides in March and September,
other cycles, such as those over 19 years and 1600 years, arising from further complex gravitational interactions.

The range of a spring tide is commonly about twice that of a neap tide, whereas the longer period cycles impose smaller perturbations. In the open ocean, the maximum amplitude of the tides is about one meter. Tidal amplitudes a

This is mainly caused by shelving of the sea bed and funneling of the water by estuaries. In some cases the tidal range can be further amplified by reflection of the tidal wave by the coastline or resonance. This is a special effect that occurs in long, trumpet–shaped estuaries, when the length of the estuary is

close to one quarter of the tidal wave length. For example, these effects combine

UK. As a result of these various factors, the tidal range can vary substantially between different points on a coastline.

The amount of energy obtainable from a tidal energy scheme therefore varies with location and time. Output changes as the tide ebbs and floods each day. It can also vary by a factor of about four over a spring–neap cycle.

Tidal energy is, however, highly predictable in both amount and timing.

The available energy is approximately proportional to the square of the tidal range. Extraction of energy from the tides is considered to be practical only at those sites where the energy is concentrated in the form of large tides and the geography provides suitable sites for tidal plant construction. Such sites are not commonplace but a considerable number have been identified in the UK, France, Eastern Canada, the Pacific coast of Russia, Korea, China, Mexico and Chile. Other sites have been identified along the Patagonian coast of Argentina, Western Australia and Western India.

Tidal barrages work rather like a hydro–electric scheme, except that the dam is much bigger. A huge dam (called a “barrage”) is built across a river estuary. When the tide goes in and out, the water flows through tunnels in the dam. The ebb and flow of the tides can be used to turn a turbine, or it can be used to push air through a pipe, which then turns a turbine.

The largest tidal power station in the world (and the only one in Europe) is the La Rance estuary in northern France, built in 1966. It consists of 24

bulb turbines with a capacity of 10MWe each. A major drawback of tidal power stations is that they can only generate when the tide is flowing in or out. In other words, only for 10 hours each day. However, tides are totally predictable, so we can plan to have other power stations generating at those times when the tidal station is out of action.

Tidal energy projects based on barrages are capital–
intensive with relatively high unit costs per installed kilowatt. The long construct
for the larger schemes and low load factors would result in high unit costs
of energy, especially given the demands of private sector investors. The economi
specific
conditions and the necessity for ship locks where access for navigation is require
site–specific conditions, it is unlikely that significant cost reductions could be
achieved. Predicted unit costs of generation are therefore unlikely to change
and currently remain uncompetitive with conventional fossil–fuel alternatives.

Some non–energy benefits would stem from the development of tidal en-

ergy schemes. However, they would yield a relatively minor monetary value
in proportion to the total scheme cost. These benefits are difficult to quantify
accurately and may not necessarily accrue to the barrage developer. Employment
creation of some permanent long–term employment from associated regional
economic development.

Tidal energy can also be exploited directly from marine currents induced
by the combined lunar and solar gravitational forces responsible for tides.

These forces cause semi–
diurnal movement in water in shallow seas, particularly where coastal morpholog
around headlands or between islands.

This phenomenon produces strong currents, or tidal streams, which are
prevalent around the British Isles and many other parts of the world where
there are similar conditions. These currents are particularly prevalent where
there is a time difference in tidal cycles between two sections of coastal sea.

The flow is cyclical, increasing in velocity and then decreasing before switching
to the opposite direction. The kinetic energy within these currents could be
converted to electricity, by placing free standing turbo–generating equipment
in offshore areas. The benefits from utilizing marine currents are given below:

• marine currents have four times the energy density of a good wind site (diameter of water turbines less than half that of a wind turbine),

• the water velocities and therefore power outputs are completely predictable,

• water turbines will not need to be designed for extreme atmospheric fluctuations as required with wind turbines, (the design can be better cost–optimized),

• with increased conflicts over land use, water turbines offer a solution that will not occupy land and has minimal or zero visual impact, and

• the technology is potentially modular and avoids the need for large civil engineering works.

Economic prospects for alternative forms of tidal energy remain uncertain, largely because there is little published data on the costs or performance of either marine current generators or bunded reservoir schemes. Until further

information is made available it is not possible to make a rational judgment on their prospects. However, without detailed technical information (for investors has highlighted the necessity for credible environmental assessment to ensure endorsement from regulatory authorities and potential objectors. The tidal energy advantages can be summarized as:

• no fuel is used,

• no wastes or greenhouse gases are produced,

• tides are totally predictable, therefore, electricity is produced reliably, and

• low maintenance costs.

The tidal energy disadvantages can be summarized as:

- high capital cost,
- change in the environment for many miles upstream and downstream,
- few suitable sites for tidal barrages, and
- provides power for around 10 hours only each day, when the tide is actually moving in or out.

Current research and development in the field of tidal energy includes:

- the exploitation of marine currents induced by tides.

7.8 Wave energy

Wave energy can be harnessed in coastal areas, close to the shore. Wave energy converters fixed to the shoreline are likely to be the first to be fully developed and deployed, but waves are typically 2–3 times more powerful in deep offshore waters than at the shoreline. Wave power technologies have been around for nearly thirty years. In fact the first patent for a wave energy device was filed in Paris in 1799, and by 1973, there were many patents for wave energy devices. Setbacks and a general lack of confidence have contributed to

slow progress towards proven devices that would have a good probability of becoming commercial sources of electrical power.

Concerning the world resource for wave, the highest energy waves are concentrat 60o latitude range north and south.

The power in the wave fronts varies in these areas between 30kW/m and 70kW/m with peaks to 100kW/m in the Atlantic Southwest of Ireland, the Southern Ocean and off Cape Horn. The capability to supply electricity from this resource is such that, if harnessed appropriately, 10% of the current level

of world supply could be provided.

There are several methods of getting energy from waves, but one of the most effective works like a swimming pool wave machine in reverse. At a swimming pool, air is blown in and out of a chamber beside the pool, which makes the water outside bob up and down, causing waves. At a wave power station waves arriving cause the water in the chamber to rise and fall, which means that air is forced in and out of the hole in the top of the chamber. A turbine connected with a generator placed in this hole, is turned by the air rushing in and out producing electricity. A problem with this design is that the rushing air can be very noisy, unless a silencer is fitted to the turbine. The noise is not a huge problem anyway, as the waves make quite a bit of noise themselves.

A new approach which is under development known as pelamis (named after a sea–snake), consists of a series of cylindrical segments connected by hinged joints. As waves run down the length of the device and actuate the joints, hydraulic cylinders incorporated in the joints pump oil to drive a hydraulic smoothing system. Electricity generated in each joint is transmitted to shore by a common subsea cable. The slack–moored device will be around 130m long and 3.5m in diameter. The pelamis is in for general deployment offshore and is designed to use technology already availa scale version has a continuously rated power output of 0.75MWe. Currently a one–seventh–scale prototype is being prepared for deployment. The wave energy advantages can be summarized as:

• no fuel is used,

• no wastes or greenhouse gases are produced, and

• low maintenance costs.

The wave energy disadvantages can be summarized as:

• depends on the waves; sometimes many loads of energy available, sometimes n

• a suitable site is required, where waves are consistently strong,

• some designs are noisy, and

• must be able to withstand very rough weather.

Current research and development in the field of wave energy includes:

• the development of offshore wave energy collection concept, using a floating tube called pelamis.

Fundamentals of Energy Regulation

Chapter 8

Future Sustainable Energy

Systems and Methodologies

8.1

Large–scale battery systems for electricity storage

Balancing power supply and demand is always a complex process. When large amounts of renewable energy sources for power generation (RES-E), such as photovoltaic (PV), wind and tidal energy, which can change abruptly with weather conditions, are integrated into the grid, this balancing process becomes e follow,
adjusting to changes in wind and PV input over short or long time spans, as well as compensating for long–term changes.

While conventional power generation plants may take several minutes or even hours to come online and will consume fuel even on spinning reserve standby, storing renewable energy for later use effectively produces no emissions

Others can be deployed rapidly to whenever they are required, but currently offer restricted capacity, often at high cost.

Although, due to their cost, batteries traditionally have not widely been used for large scale energy storage, they are now used for energy and power

applications. Energy applications involve storage system discharge over peri-139

ods of hours (typically one discharge cycle per day) with correspondingly long charging periods. Power applications involve comparatively short periods of discharge (seconds to minutes), short recharging periods and often require many cycles per day. Secondary batteries, such as lead–acid and lithium–ion batteries can be deployed for energy storage, but require some re–engineering for grid applications.

For grid stabilization, or grid support, energy storage systems currently consist of large installations of lead–acid batteries as the standard technology.

The primary function of grid support is to provide spinning reserve in the event of power plant or transmission line equipment failure, that is, excess capacity to provide power as other power plants are brought online, especially in the case of isolated power systems. These systems can take energy from the grid when either the frequency or voltage is too high and return that energy to the grid when the frequency or voltage begins to sag. The current implementati
including shifting peak loads, and supporting RES-
E, will require longer durations of storage and therefore re–
engineering of storage systems to handle greater energy to power ratios.

Several types of batteries are used for large scale energy storage, such as:

- Lead–acid batteries
- Lithium–ion batteries
- Nickel–cadmium batteries
- Sodium–sulfur batteries
- Flow batteries

• Vanadium redox battery

• Zinc–bromine battery

All consist of electrochemical cells, though no single cell type is suitable for all applications.

8.1.1 Lead–acid batteries

Lead–
acid batteries, invented in 1859, are the oldest type of rechargeable battery and th
acid batteries Fundamentals of Energy Regulation

is uncomplicated and manufacturing costs are low, however, such batteries are slow to charge, cannot be fully discharged and have a limited number of charge/discharge cycles, due to their low energy–to–weight ratio and their low energy–to–volume ratio. The lead and sulfuric acid used are also highly toxic and create environmental hazards, which can be particularly ironic when used to accompany clean sources of power such as PV systems.

The lead–
acid battery chemistry can be modified for grid storage applications beyond stabil
carbon electrodes are designed to combine high energy density
of a well designed battery with the high specific power obtained via charging and discharging of the electrochemical double layer.

Lead–carbon electrode research has been focused on the extension of cycle life durability and specific power. Carbon is added to the negative electrodes, and while the carbon does not change the nature of the charge transfer reactions, i
charging cycles, which is one of the principal failure modes of traditional lead–

acid batteries. In these applications, it is required to have relatively deep discharg

in valve regulated lead–acid (VRLA) batteries, the cycle life is improved up to a factor of ten at significant rates.

In RES-E applications multiple deep–cycle lead–acid (DCLA) batteries, which provide a steady current over a long time period, are connected together to form a battery bank. Indeed, banks of up to 1MW of lead–acid batteries are already being used to stabilize wind farm power generation. For instance, DCLA are designed for backup and peak shifting in off-grid and grid–tied PV systems.

8.1.2 Lithium–ion batteries

Lithium–ion batteries, have achieved significant penetration into the portable consumer electronics markets and are making the transition into hybrid and electric vehicle applications and have opportunities in grid storage as well.

If the industry's growth in the vehicles and consumer electronics markets can yield improvements and manufacturing economies of scale, they will likely find their way into grid storage applications too.

Developers are seeking to lower maintenance and operating costs, deliver high efficiency, and ensure that large banks of batteries can be controlled.

Continued cost reduction, lifetime and state–of–charge improvements, will be critical for this battery chemistry to expand into these grid applications. There are three types of lithium–ion batteries in commercial use, such as, cobalt, manganese and phosphate. When lithium–ion batteries are used for utility–scale applications, it is to perform regulation and power management services

and will be used for minutes of runtime.

8.1.3

Nickel–cadmium batteries

A nickel–
cadmium battery is made up of a positive electrode with nickel oxyhydroxide as t
cadmium. These are separated by a nylon divider. The electrolyte, which
undergoes no significant changes during operation, is aqueous potassium hydroxi
produces nickel hydroxide and a hydroxide ion. Cadmium hydroxide is produced
reversed. However, during charging, oxygen can be produced at the positive
electrode and hydrogen can be produced at the negative electrode. As a result
some venting and water addition is required, but much less than required for
a lead–acid battery.

There are two nickel–cadmium battery designs, the sealed and the vented.

Sealed nickel–
cadmium batteries are the common, everyday rechargeable batteries used in a rem
batteries, unless a fault occurs. Vented nickel–cadmium batteries have the
same operating principles as sealed ones, but gas is released if overcharging
or rapid discharging occurs. The oxygen and hydrogen are released through a
low pressure release valve making the battery safer, lighter, more economical,
and more robust than sealed nickel–cadmium batteries.

Sealed nickel–
cadmium batteries are used commonly in commercial electronic products such as
rechargeable power are important. Vented nickel–cadmium batteries are used
in aircraft and diesel engine starters, where large energy per weight and volume
are critical. Nickel–cadmium batteries are ideal for protecting power quality
against voltage sags and providing standby power in harsh conditions.

Recently, nickel–cadmium batteries have become popular as storage for
solar generation because they can withstand high temperatures. However,
they do not perform well during peak shaving applications, and consequently

are generally avoided for energy management systems.

8.1.4

Sodium–sulfur batteries

Sodium–
sulfur batteries are rechargeable high temperature battery technologies that utilize
scale electric utility energy storage applications. Candidate uses include load
leveling, power quality and peak shaving, as well as renewable energy manageme
sulfur battery is a type of molten metal
battery constructed from sodium and sulfur. This type of battery has a high
energy density, high efficiency of charge/discharge (75–86%), long cycle life,
and is fabricated from inexpensive materials. However, because of the operating t
sodium polysulfide discharge products, such cells are primarily suitable for
large–scale, non–mobile applications such as grid energy storage.

Sodium β’-Alumina (beta double–prime alumina) is a fast ion conductor
material and is used as a separator in several types of molten salt electrochemical
integrity. In the mid–1980s, the development of the sodium/metal–chloride
system was launched. This technology offered potentially easier solutions to
some of the development issues that sodium/sulfur was experiencing at the time.

Sodium/metal chloride cells, referred to as ZEBRA cells (ZEolite Battery
Research Africa), also operate at relatively high temperatures, use a negative
electrode composed of liquid sodium, and use a ceramic electrolyte to separate
this electrode from the positive electrode. In these respects, they are similar to
sodium/sulfur cells. However, sodium/metal chloride cells include a secondary
electrolyte of molten sodium tetrachloroaluminate ($NaAlCl_4$) in the positive
electrode section, and an insoluble transition metal chloride ($FeCl_2$ or $NiCl_2$)
or a mix of such chlorides, as the positive electrode. The advantages are that
the cells have a higher voltage, wider operating temperature range, are less
corrosive and have safer reaction products.

From the time of their invention through the mid–
1990s, these two technologies were among the leading candidates believed to be

Utility–scale sodium–sulfur batteries are manufactured by only one company.

8.1.5

Flow batteries

A flow battery is a form of rechargeable battery in which electrolyte containing one or more dissolved electro–active species flows through an electrochemical cell that converts chemical energy directly to electricity. Additional electrolyte is stored externally, generally in tanks, and is usually pumped through the cell (or cells) of the reactor, although gravity feed systems are also available.

Flow batteries can be rapidly recharged by replacing the electrolyte liquid (in a similar way to refilling fuel tanks for internal combustion engines) while simultaneously recovering the spent material that would be recharged in a separate step.

Various classes of flow batteries exist including the redox[1] flow battery, a reversible fuel cell in which all electro–active components are dissolved in the electrolyte. If one or more electro–active components are deposited as a solid layer, the system is known as a hybrid flow battery, that is, the electrochemical cell contains one battery electrode and one fuel cell electrode. The main difference between these two types of flow batteries is that the energy of the redox flow battery, as with other fuel cells, is fully decoupled from the power, because the energy is related to the electrolyte volume, i.e., to the tank size, and the power to the electrode area, that is, to the reactor size. The hybrid flow battery, similar to typical batteries, is limited in energy by the size of the battery electrode, i.e., to the reactor size.

Energy producing electrochemical cells are generally divided into two categories. reactions, are termed primary cells, while rechargeable cells with reversible reactions are termed secondary cells. Using this historical convention, a redox

flow battery is better described as a secondary fuel cell or regenerative fuel cell, with the fundamental difference between batteries and fuel cells being whether energy is stored in a solid state electrode material (batteries) or in the electrolyte (fuel cells). This difference leads to the decoupling of energy and power in a fuel cell described above. Example of redox flow batteries is the vanadium redox flow battery, whereas for hybrid flow battery is the zinc-bromine battery.

Redox flow batteries, and to a lesser extent hybrid flow batteries, have the advantages of

- flexible layout, due to separation of the power and energy components,

[1]Reduction–oxidation.

- long cycle life, because there are no solid-solid phase changes,

- quick response times, no need for equalization charging since the overcharging

- no harmful emissions.

Some types also offer easy state–of–charge determination, through voltage dependence on charge, low maintenance and tolerance to overcharge and/or overdischarge.

On the negative side, flow batteries are rather complicated in comparison with standard batteries as they may require pumps, sensors, control units and secondary containment vessels. The energy densities vary considerably but are, in general, rather low compared to portable batteries, such as the lithium–ion. Also, they have high initial self–discharge rate.

8.1.6

Vanadium redox battery

The vanadium redox battery is a type of rechargeable flow battery that employs v energy. The vanadium redox battery exploits the ability of vanadium to exist in solution in four different oxidation states, and uses this property to make a battery that has just one electro–
active element instead of two. The vanadium redox battery is a particularly clean and a long life cycle. Its energy density is rather low, about 40Wh/kg, though recent research indicates that a modified electrolyte solution produces a 70%

improvement in energy density.

Vanadium prices are volatile, though, with the increased demand for battery use l reducing self–discharge losses and on lower cost electrode structures. Self–

discharge is being addressed by only pumping electrolyte through the electrochen

The main advantages of the vanadium redox battery are that it can offer almost unlimited capacity simply by using larger and larger storage tanks, it can be left completely discharged for long periods with no ill effects, it can be recharged simply by replacing the electrolyte if no power source is available to charge it, and if the electrolytes are accidentally mixed, the battery suffers no permanent damage. The main disadvantages with vanadium redox technology

are a relatively poor energy–to–volume ratio, and the system complexity in comparison with standard storage batteries.

The extremely large capacities possible from vanadium redox batteries make them well suited to use in large power storage applications such as helping to average out the production of highly variable generation sources such as wind or solar power, or to help generators cope with large surges in demand.

The limited self–discharge characteristics of vanadium redox batteries make them useful in applications where the batteries must be stored for long periods of time with little maintenance while maintaining a ready state. This has led to their adoption in some military electronics. Their extremely rapid response times also make them superbly well suited to UPS type applications, where they can be used to replace lead–acid batteries and even diesel generators.

8.1.7

Zinc–bromine battery

The zinc-bromine flow battery is a type of hybrid flow battery and is stored in two tanks. When the battery is charged or discharged, the solutions (electrolyte tank is used to store the electrolyte for the positive electrode reactions and the other for the negative. Zinc–bromine batteries from different manufacturers have energy densities ranging from 34.4–54Wh/kg.

The predominantly aqueous electrolyte is composed of zinc bromide salt dissolved in water. During charge, metallic zinc is plated from the electrolyte solution onto the negative electrode surfaces in the cell stacks. Bromide is converted to bromine at the positive electrode surface of the cell stack and is immediately stored as a safe, chemically complex organic phase in the electrolyte density polyethylene (HDPE) cell
stack has up to 60 bipolar, plastic electrodes between a pair of anode and cathode end blocks.

The zinc–bromine battery can be regarded as an electroplating machine.

During charging zinc is electroplated onto conductive electrodes, while at the same time bromine is formed. On discharge the reverse process occurs, the metallic zinc plated on the negative electrodes dissolves in the electrolyte and is available to be plated again at the next charge cycle. It can be left fully discharged indefinitely without damage. The primary features of the zinc bromine battery are:

METHODOLOGIES

• high energy density relative to lead–acid batteries,

• 100% depth of discharge capability on a daily basis,

• high cycle life of more than 2000 cycles at 100% depth of discharge, at which point the battery can be serviced to increase cycle life to over 3500

cycles,

• no shelf life limitations as zinc–bromine batteries are non–perishable, unlike lead–acid and lithium–ion batteries,

• scalable capacities from 10kWh to over 500kWh systems, and

• the ability to store energy from any electricity generating source.

Zinc–bromine flow batteries have the potential to provide energy storage solutions at a lower overall cost than other energy storage systems such as lead–acid, vanadium redox, sodium–sulfur, lithium–ion and others.

8.1.8

Operational and planned large scale battery energy systems

Currently around the world the largest battery energy storage systems use sodium–
sulfur batteries, whereas the flow batteries and especially the vanadium redox flo

The battery energy storage systems are mainly used as ancillary services or for supporting the large scale solar and wind integration in existing power systems, by providing grid stabilization, frequency regulation and wind and solar energy smoothing.

Specifically, the Amplex Group has employed a battery energy storage system wi
sulfur batteries in the United Arab Emirates, with a capacity of 350MWe, which is used as ancillary service for grid stabilization, frequency regulation, voltage support, power quality, load shifting and energy arbitrage.

Furthermore, in Laurel Mountain of West Virginia of USA, a battery energy storage system with lithium–ion batteries and a capacity of 32MWe and 8MWh has been employed, which is used for helping large scale wind integration in the existing power system by providing frequency regulation and wind energy smoothing.

The Golden Valley Electric Association has employed a battery energy storage system with nickel–
cadmium batteries in Alaska of USA, with a capacity of 27MWe and 14.6MWh, v
reserve and power system stabilization. Moreover, the Puerto Rico Electric Power Authority has employed a battery energy storage system with lead–

acid batteries in Puerto Rico, with a capacity of 20MWe and 14MWh, which is used as ancillary service for frequency control and spinning reserve. Finally, The Sumitomo Densetsu Office has employed a battery energy storage system with vanadium redox flow batteries in Japan, with a capacity of 3MWe and 0.8MWh, which is used as ancillary service for peak shaving.

Regarding the planned large scale battery systems, the most important is the Rubenius battery energy system in California, USA, which will have a capacity of 1000MWe and will require an area of 1,416,400m2. The battery system that will be used is sodium–sulfur type and the system will be used for helping for large scale solar and wind integration in the existing power system, by providing grid stabilization, frequency regulation, voltage support, power quality, load shifting and energy arbitrage.

8.2

From the ‘camel curve’ to the ‘duck curve’ on electric systems with increasing solar power

The duck curve refers to the effect that solar power has on demand for utility electricity. Thus, all interested parties involved in solar energy should know

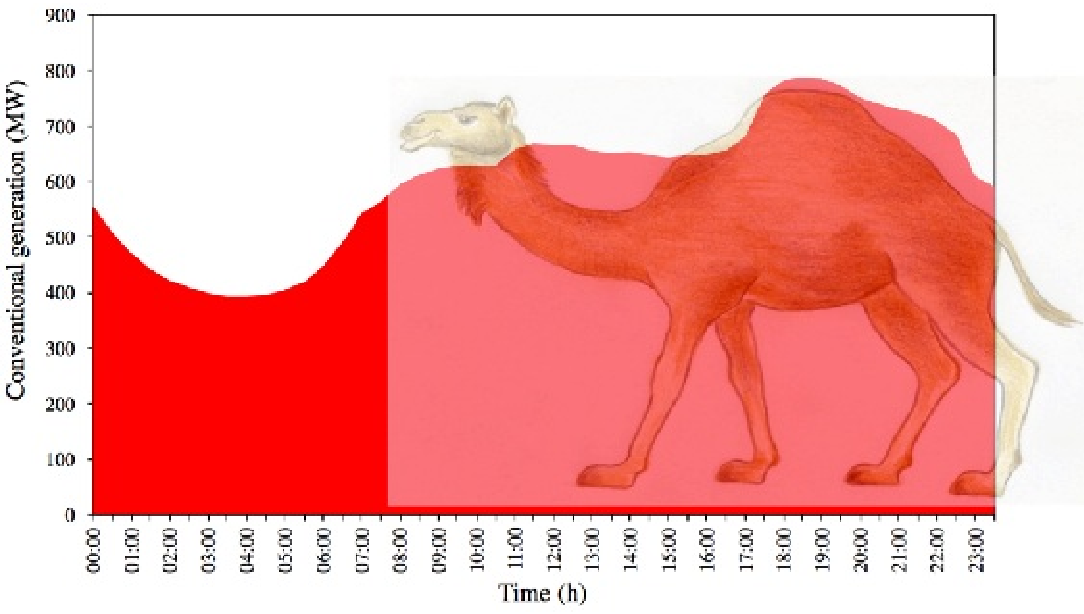
about the duck curve effect.

For many, many decades, demand for electricity followed a fairly predictable dail predicting and satisfying it. The addition of large amounts of solar power to the grid promises to fundamentally change the shape of that daily demand profile, in ways that make grid operators work difficult about maintaining power and reliability.

8.2.1

The 'camel curve'

In particular, electricity demand used to have a predictable, manageable shape (namely the camel curve) as shown in Figure 8.1. Demand for electricity varies throughout the day, but it does so in fairly predictable ways. It rises in the



morning to a little hump before noon, levels out over midday, and then rises to a higher hump in the evening, when everyone gets home from work and

turns on their TVs and stoves.

Figure 8.1: The camel curve effect.

If you squint, you can kind of see a camel's back, with its hump. The exact shape of this curve varies from place to place and season to season, obviously. In some times and places the humps are more pronounced; in temperate climates, with less heating and cooling demand, they're a little flatter. But in most cases, load curves share a few key characteristics. There are two daily humps. Demand never gets too high or too low, meaning it stays within a reasonably manageable range. And the ramp–ups and ramp–downs of demand are fairly gradual. For near a century, that's the demand utilities met, and they got really good at it.

For that baseline amount of energy that's always needed, namely the base load, they run big power plants, usually steam turbines, around the clock.

These plants are typically slow (and expensive) to start or stop, but cheap once they are running. Then there's intermediate load, with the next-cheapest tier of power plants, and at the top of that second hump, peak load, satisfied by (usually gas turbines) peaker plants that are expensive to run but easy to

ramp up and down quickly.

It all worked out fine until wind power and solar power came along. They do different things to the load curve, though, in this article we're focusing on solar power. The thing about solar power is you can't schedule it like you can a power plant. The sun shines when the sun shines, typically from morning to mid-afternoon. When the sun is out and a customer's solar panel's are generating energy, that customer is using less of the energy put on the grid by the utility.

In other words, from the grid operator's point of view, solar energy doesn't

look like a power plant at all, which are controllable, or dispatchable, but it looks like a reduction in demand. It's a reduction in demand for the power supplied by the grid operator's power plants, a somewhat predictable reduction, b supply total demand. They have to supply total demand minus solar power.

Total load minus solar power is known a "net load". That's the new target utilities have to hit.

8.2.2

The 'duck curve'

And when solar power starts getting big, net load starts looking a lot different from old–fashioned load. With lots of solar power, load curves start looking like a duck curve. As solar power penetration increases, things are changing.

Demand is suppressed more during the day, when the sun is up. And year by year when solar power penetration increases we expect the effect to become more and more pronounced, until the load curve starts looking like a "duck curve" as illustrated in Figure 8.2.

One notable thing about the duck curve effect is that it wreaks havoc on the revenue of power producers and utilities. That gives them every reason to exaggerate its inevitability and its danger.

8.2.3

What is wrong with the 'duck curve'

From the point of view of the grid operator, worries about the duck curve are threefold:

Steep, tall ramps: the ramps, those times when net load is rising or falling, no longer look like the gentle slope of a camel's hump. They get steep and tall (like a duck's belly) and relatively quick. That means grid

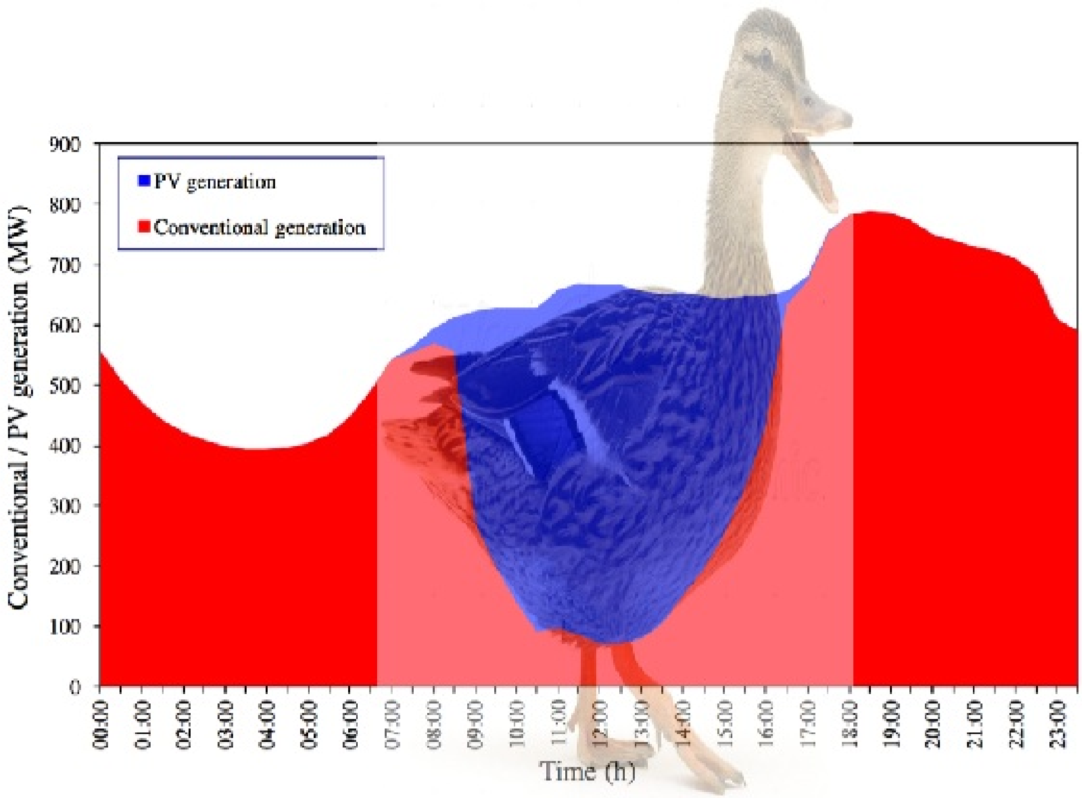


Figure 8.2: The duck curve effect.

operators are forced to take a bunch of power plants offline, or put a bunch online, rapidly. What’s especially unfortunate is that the sun tends to go down just before the evening peak of demand, which means net load goes from very low to very high, very quickly, and then down low again. Grid operators don’t like steep ramps. It is expensive and

highly polluting to turn a bunch of plants down (or off) and then put them back up again all at once. It also makes voltage and frequency management more difficult. Steam turbines are not good in this role, as they are slow to ramp. For the most part, for fast–responding power plants, utilities turn to gas turbines. So enough conventional capacity to supply the evening peak is required, but for most of the midday, it doesn't need any of it. That amounts to a lot of conventional plants sitting around a lot of the time, with low capacity factors, but being ramped up and down frequently, increasing operating and maintenance costs.

Overgeneration and curtailment: when the duck gets really fat, its belly starts hanging closer to the bottom of the chart, net load gets closer and closer to zero around midday. That means all the peaker plants get shut down, all the intermediate plants get shut down, and some of the base load plants start to get ramped down too. And then a few hours later, they all get ramped back up. For one thing, that's expensive. For another, grids need a certain amount of reserve power online at all times as a buffer in case of accident or disruption. If so much solar power comes online that it starts to eat into those reserves, solar power will be curtailed, i.e., the grid will stop accepting it. For example, in Hawaii, where 10 percent of customers have rooftop solar, the duck's belly has hit bottom a few times with a negative net load, which can affect system voltage and stability. In Hawaii, the duck's belly is so low, and the ramp up to its head so high, they've started calling it the "Nessie curve", after the Loch Ness Monster. These worries have led Hawaiian authorities to pull back on solar power and institute new interconnection standards since currently the grid has no communication with most of those solar panels and no ability to control or predict them.

Frequency response: for stability, the grid must closely balance supply and demand, second by second. Frequency is maintained at around 50Hz. In case of a sudden disruption, unexpected loss of a power plant, transmis-

sion line, or large load, the grid needs resources capable of ramping up or down quickly to compensate. This is done by automated frequency response systems, usually on conventional power plants. If solar starts shutting down all those plants in the middle of the day, the grid loses those resources, and with it some stability.

There are lots and lots of ways to flatten the duck curve. From an engineering per

There may be some level of wind and solar penetration where the cost of integrat

8.3

Net–metering mechanism for photovoltaic systems

A feed–in tariff (FiT) scheme provides a guaranteed premium price to the green electricity producer and put an obligation on the grid operators to purchase the generated electricity output. The price is typically guaranteed for a long period in order to encourage investment in new renewable energy sources for power generation (RES-E) plants. FiT schemes are supply–side measures that push green electricity onto the market and are mostly used for the initial promotion of RES-E technologies in a given region or country. These schemes are well known for their success in deploying large amounts of wind, biomass and solar energy (both photovoltaics (PV) and concentrated solar power systems) mainly during the first steps of introducing RES-E technologies in a power system. The biggest advantage of FiT schemes is the long–term certainty of financial support, which lowers investment risks considerably.

In the case of households installing rooftop solar PV systems can receive special pricing under net–
metering agreements. These agreements allow households with rooftop solar to b
using the larger grid to store surplus generation from their panels during sunny times and return it when the sun isn't shining. If a household generates more electricity than it consumes over the course of a month, it obtains a credit that rolls over for use in future months. Net–
metering agreements often include a monthly fee to support billing, transmission,
load-shifting services.

A growing concern is that the utility has many costs besides the fuel used in electricity generation, and most of these fixed costs are lumped in with

per kWh charges. As a result, under current net–metering agreements, when a solar customer provides their own power, they don't pay the fixed cost component for each kWh they produce. Under a revenue–decoupling rule, those costs are shifted to households and businesses without rooftop solar. As less power is sold, fixed costs per kWh are rising fast.

So what would an optimum net–metering agreement look like? There is no single answer to this question, but there are some basic economic concepts that ought to guide policy. A perfectly efficient scheme would set real–time per kWh prices equal to the marginal generation cost, and allow anyone to buy or sell as much power as they want at this price. Marginal cost is the incremental cost of power production, that is the cost of generating one more kWh. This cost can vary a lot depending on total demand and the amount of renewable power, among other things, so ideal prices would vary over the course of each day, week, season and year.

This variation is likely to become especially pronounced as the variable supply from renewable sources becomes more prominent. Fixed costs could be handled a few ways, but would not necessarily be included in the per kWh price today. Implementing true marginal–cost pricing would solve problems with net metering agreements and make achieving the country's renewable energy goals much less costly overall. It would also entail a number of challenges.

8.3.1 The net–metering concept

Net–metering scheme was initially conceived as a simple way to encourage early technology adoption, and may well have been justified for many reasons.

But as solar installations continue to increase, much of the logic supporting net–metering vanishes. One key challenge with solar PV is that its supply is variable and unpredictable. Variability isn't much of a problem when solar makes up a relatively small share of demand, as existing power plants can

easily cycle generation up or down to accommodate changing supply from solar. After all, cycling is what power plants have always done, since demand itself tends to vary unpredictably. But when renewables make up an increasing share of the load, it becomes increasingly difficult to balance renewable supply by cycling traditional power plants.

Today, these challenges are most acute on isolated power systems, where supply from variable renewable energy sources often exceeds what the system can accept, so the power must be curtailed. Curtailment happens when exist-

ing power plants are cycled down to their minimum operating load, and that minimum load, plus the renewable energy, exceeds the amount demanded.

Thus, renewables can be curtailed even when they comprise far less that the total energy demanded.

A potentially critical problem is that distributed solar, as is the case with rooftop net-metering PVs, cannot be curtailed like the utility–
scale installations. Instead, if overproduction were to occur, the excess power wo
the power system operating frequency above the allowed range. This would be highly disruptive and could even lead to a system wide blackout. Besides challen
of solar energy from residential circuits into the larger grid are also important.

Net metering is an electricity policy which allows utility customers to offset some or all of their electricity use with self produced electricity from RESE syste
and record energy flow in both directions. The meter spins forward when a customer is drawing power from the utility grid (i.e., using more energy than they are producing) and spins backward when energy is being sent back to the grid (i.e., using less energy than they are producing). At the end of a given month, the customer is billed only for the net electricity used. Net metering works only for grid connected systems and what makes it so beneficial, besides offsetting a home's energy consumption with a RES-E system, is that excess energy sent to the utility can be sold back at retail price.

If more energy is produced than consumed, producers receive benefit for this positive balance, such as, renewable energy credits (REC), which is credited the year a surplus remains, then the customer depending on the utility policy may:

(i) paid for the total REC collected at avoidance cost rate or retail cost rate, or,

(ii) the total REC collected can be transferred and could be used as a compensatic
(iii) the total REC collected are granted back to the utility.

An example of how net metering works, can be illustrated by the following description of a typical day of a residential customer. Such a customer would wake up early for his job and usually on most days, will be out of the house

before sunrise. In these dark morning hours, the only consumption would concern the making of coffee and breakfast and watching the morning news on TV. Therefore, the electric meter spins forward as the customer consumes electricity from the grid. When the customer leaves the house for work, the solar panels start producing electricity as the sun rises and this electricity is provided to the grid. The meter now spins in reverse. When the customer returns at night to cook dinner and relax in front of the TV, the meter spins forward again as more electricity is consumed that produced. In this typical day, the customer's bill will record only his net consumption of electricity from the grid.

Should it be a hot sunny month (when the grid needs the most help), or a month in which the customer's consumption of electricity is low, any excess electricity the system generates is rolled over to the next bill. Net metering allows for the production of electricity that reduces demand on a strained grid.

For the utility, this is exactly the same result as if the customer had installed a more efficient refrigerator. The only way the utility would know the difference between using more efficient technologies (such as a refrigerator) and the use

of customer sited distributed generation (DG) (such as a PV system), is if the utility installed a costly additional meter at customer's home and undertook the burden and expense of reading both meters and billing the customer for the result of this process.

Some variations of the net metering mechanism are the time of use (TOU) metering and the market rate net metering systems:
TOU net metering systems employs a specialized reversible smart meter that is programmed to determine electricity usage any time during the day. TOU allows utility rates and charges to be assessed based on when the electricity was used, i.e., day or night and seasonal rates. Typically the production cost of electricity is highest during the daytime peak usage period is a significant issue for RES-E, since, for example, solar power systems tend to produce energy during the daytime peak-
price period, and produce little or no power during the night period, when price is market rate net metering systems, the user's energy use is priced dynamically according to some function of wholesale electric prices. The users'

meters are programmed remotely to calculate the value and are read remotely. Net metering applies such variable pricing to excess power

produced by qualifying systems

Market rate net metering systems have been implemented in California since 2006 and under the terms of California's net metering rules are applicable to qualifying PV and wind systems. Under California law the payback for surplus electricity sent to the grid must be equal to the (variable, in this case) price charged at that time. It can never be negative, meaning you cannot make money from selling the electricity back. If you generate more electricity than you use then over a period of a month you will be billed zero and not make any money, in effect you give away your extra energy if you do not use it.

Net metering enables small systems to result in zero annual net cost to the consumer provided that the consumer is able to shift demand loads to a lower price time, such as by chilling water at a low cost time for later use in air conditioning, or by charging a battery electric vehicle during off–peak times, while the electricity generated at peak demand time can be sent to the grid rather than used locally. No credit is given for annual surplus production.

8.3.2 Benefits and misconceptions

There are benefits from net metering that accrue to:

- the utility,
- the customer, and
- the community.

For the utility, a well–designed net metering policy provides a simple, low cost, and easily administered way to deal with PV residential systems. Utilities obtain electricity and capacity from small, distributed PV installations. This is electricity they don’t have to generate themselves or purchase on the market.

For PV systems, this generation takes place every day of the year with a very high correlation with utility peak loads. Utilities call this a high load carrying capability since sunshine is relatively easy to predict. Thus, utilities obtain the benefit of additional capacity in their service territory paid for by their customers. PV residential systems can, also, strengthen the distribution grid, especially in rural areas. This is because voltage tends to drop at the end of

long distribution lines when loads are high, and if it drops below a threshold level, the breakers will trip and a temporary blackout occurs.

Grid connected PV systems tied to the distribution grid strengthen voltage and improve overall service. And this grid support can defer maintenance and upgrades in the power distribution system, which is a tangible benefit to utilities. Customers benefit from net metering of PV residential systems because they obtain a long–term guarantee of low utility bills. Communities benefit from the investment in local generation. This investment not only increases local property values but increases local business opportunities as well. It is the difference between paying rent and paying a mortgage.

There are also some misconceptions about net metering, such as that net metering hurts the utility bottom line by reducing revenues. This argument is similar to the one against energy efficiency that customers reducing their purchas bought a PV system and put it on their roofs. Small net metering markets does not affect even a fraction of a percentage point on a bottom line of any utility that reports these figures publicly. Nevertheless, any net metering policy sh development of the market. If PVs, and especially energy efficiency, which has a much larger potential for impacting rates than PVs, gets to the point where it actually reduces utility revenues, then tariffs should be restructured to guarantee that service.

Another misconception is that net metering represents a subsidy from one group of customers to another. This argument has to do with the methodology that utilities use to charge customers. The argument is that utilities charge all customers in the same class a single rate, which represents an average cost of doing business plus profit. Thus, a household who uses a lot of electricity during the day when the cost of obtaining electricity is higher pays the same as the household who uses electricity at night during off–peak hours. One could argue that one type of consumer subsidizes another based on patterns of consumption, etc.

Utilities and their customers have supported this averaging formula for years. For example, building a new home represents a cost for a utility because it must invest in new generating capacity in order to supply this electricity.

Therefore, customers subsidize solar systems through net metering no more than they subsidize construction of new homes. Both represent expanding business opportunities, and electric utilities have figured out a way to accom-

modate this economic growth through existing tariff structures for more than a century.

A final misconception is that net metering represents a burden for small utilities. The opposite is actually true because large organizations are better equipped to handle more complicated arrangements. Net metering is as simple as it gets to administer because it requires no special equipment, no new rates to establish and no new procedures. All that is required is that the utility adds a line in the ledger for each net metering customer to carry forward credits until the end of the year. Compare this with the alternative of FiT supporting scheme, which requires installation of another meter. Then the utility must make special trips to read this meter and readjust its accounting procedures to keep track of another meter for a single account. The cost of reading the extra meters for residential PV systems alone outweighs the cost of net metering.

8.3.3 Potential problems with net–metering scheme

Net–metering limits the amount of electricity that households can sell back to the grid since it can discourage homes and businesses from conserving energy or investing in energy efficiency. This arises because households have a strong incentive to install solar generation capacity that exceeds the amount they consumed when paying retail prices. Facing a lower cost of electricity, household fluorescent lamps or LEDs, replace old appliances with new energy efficient units, limit use of air conditioning and so on.

And to the extent that households are uncertain about future demand, it costs less to over–install solar than to pay the retail price for electricity, so it's better to install too much than to install too little. Under the net–metering scheme, once a household or business installs greater capacity than they use, they effectively face a zero price for electricity up to that capacity, which further discourages conservation. This may not be a problem during the day, when solar power is abundant, but under net–metering customers may also increase hard–to–serve evening loads at no cost.

In time, as both utility–
scale and residential solar installations grow, midday electricity is likely to becom
electricity, so it makes little sense to apply the same rate for electricity sent to the grid as drawn from it. Even today, the electricity marginal cost can vary considerably depending on total demand and the mix of generation currently

being used. This variability in cost is likely to become much more extreme as renewable energy grows. When rates differ from marginal cost, perverse inefficiencies occur leading to curtailments.

8.4

Electric vehicle technologies

Growing concerns over climate change and security of energy supply are driving
electric vehicle propulsion systems capable of delivering long–
term sustainability. Globally three quarters of transport greenhouse emissions con
road transport. The transport sector is especially vulnerable to oil supply disruptic
emissions, concerns over air quality and noise, especially in urban areas are also under consideration.

Electric vehicles are a promising technology for the drastic reduction of road transport emissions. This is an important element in reducing carbon dioxide (CO2) emissions, air pollutants and noise from passenger cars and light commercial vehicles. At the same time, the electric passenger cars that are under development are not yet competitive with conventional vehicle technology.

Costs are still high and battery technology is still under developed leading to many uncertainties with respect to crucial issues, such as battery technology, impacts on emissions, interaction with electricity generation and costs and business case of large–scale introduction.

Currently there are three main types of electric vehicles that have passed

from the demonstration to the production stage of the manufacturing process, such as:

• Hybrid electric vehicles (HEVs),

• Plug-in electric vehicles (PHEVs), and

• Full electric vehicles (FEVs).

The major difference between these types of vehicles is that for the last two types, the battery can be externally recharged.

8.4.1

Hybrid electric vehicles

A HEV is a type of hybrid vehicle, which combines two distinct power sources in order to provide driving power. The two power sources are a conventional internal combustion engine (ICE) and a battery/electric motor system. The presence of the battery and the electric motor system is intended to achieve either better vehicle fuel economy or better performance than a conventional ICE vehicle.

This is essentially achieved since the low efficiency ICE is now used in combination with a much higher efficiency power source, such as the battery.

Currently, a variety of HEV types exist in the automotive market with varying degrees of independent ICE/electric motor operation. The size of the components the control strategy of HEV.

The ratio between the maximum power of the electric motor and the maximum p hybridization ratio results in a large electric path (electric motor and battery) and

in a small electric path and a large ICE. A simplified version of hybrid power trains is the so–called mild hybrid, which has an integrated starter generator (ISG) instead of an electric propulsion motor.

Typically, HEVs are equipped with a standard ICE and a battery pack connected to an electrical motor. Full HEVs are able to perform in both the conventional vehicle transmission mode by utilizing the ICE with conventional fuel, typically gasoline, and/or in an electric power mode by using electrical power from the battery to drive the electric motor. An essential feature of a HEV is the electric motor/generator system which:

(a) when used as a generator generates electrical power to charge the battery and start the vehicle's ICE when required, and

(b) when used as a motor, drives the vehicle by turning the vehicle's wheels.

Generally, conventional HEVs are charge–sustaining, i.e., while driving they maintain their batteries at a roughly constant state–of–charge and recharging occurs only from on–board electricity generation by the ICE coupled to the motor/generator or from the recapture of kinetic energy through regenerative braking.

In a typical electric mode operation, the electric motor/generator uses power from the battery pack and acts as a motor to drive the vehicle at startup and at low vehicle speeds and acceleration where it offers high torque. The ICE, which can provide low torque at low vehicle speeds, is only engaged when higher speeds, faster acceleration or more power for charging the batteries is required and it is automatically started by the motor/generator acting as a starter.

This combined mode of vehicle operation allows the ICE to be utilized only at high efficiencies and to be normally switched off at traffic stops where it is anyway extremely inefficient. In the cases where the ICE is switched off, any accessory power requirements, e.g., air conditioning is provided by the battery pack. This limitation of ICE use results, therefore, in vehicle performance

optimization and improved efficiency and lower emissions when compared to conventional gasoline vehicles.

The HEV battery can be charged with the use of the motor/generator system, acting as a generator, both while driving and also while the car is stationary. In both cases, the vehicle's intelligence unit will be running the ICE in order to turn the generator system from where electrical charging power can then be extracted to the battery. Finally, the battery can also be charged via the regenerative braking technology. In this technology, the braking energy during the car's deceleration is used to charge the battery.

During deceleration, the regenerative brakes put the vehicle's electric motor into reverse mode and by running backwards the car's wheels are slowing down.

While running backwards, the motor also is acting as a generator producing electricity that is used to charge the car's batteries. Regenerative brakes are more effective at lower speeds and in stop–and–go driving situations, i.e., in city traffic. Hybrid cars also employ friction brakes, as a back–up system in case where regenerative braking power is not enough to fully stop the car.

HEVs typically use a nickel cadmium (NiMH) battery pack which is typically all
60% of its maximum capacity to prolong
battery life as well as to provide a reserve capacity in case of charging through regenerative braking. A typical battery pack output voltage is 273.6V with a 6.5Ah capacity and a weight of 53.3kg. The total hybrid travelling range per gasoline fill–up is 900–1200km. Essentially, the vehicle's electric travelling range, which is the distance the vehicle can travel only running on battery, is determined by the battery energy potential, while the acceleration rate and the maximum vehicle speed that can be reached in electric mode is determined

by the battery power potential. However, because of the continuous availability o
up power source, and because of the fact that HEVs
are run on charge sustaining mode without actually depleting their batteries,

electric range and maximum vehicle speed are not as critical parameters to be considered in a hybrid vehicle battery design compared to PHEVs and, more importantly, FEVs.

8.4.2

Plug–in hybrid electric vehicles

PHEVs are a new and upcoming technology in the transport sector. Basically, they are similar to HEVs in that they have both an ICE and a battery pack as a means to provide driving power. In fact, PHEVs are defined as HEVs that have a battery storage system of 4kWh or more, a means of recharging the battery from an external source and the ability to drive at least 16km in electric mode.

These vehicles are able to run on fossil fuels and on electricity or a combination c
to–grid (V2G) technology.

In terms of efficiency, PHEVs have the potential to be even more efficient than HEVs since a more limited and selective use of the ICE would increase total combined vehicle efficiency and allow the ICE to be used even closer to its peak efficiency by operating only at high vehicle speeds.

Gasoline is the typical fossil fuel used in PHEVs operation but diesel or, to a lesser extent, ethanol can also be used. PHEVs do not utilize the ICE to charge the battery to the same extend as in HEVs, where this is the primary mode of charging. Instead, these types of vehicles have a battery pack that can be fully charged by the electricity grid by plugging the vehicle into a standard electrical outlet of 120/240V AC. In addition, regenerative braking is also a feature of PHEVs which can also provide an on board battery charging alternative. Several studies have found that when charged from the electricity grid, PHEVs may emit less CO_2 and other pollutants over their entire fuel cycle than conventional ICE vehicles and HEVs.

Thus, PHEVs may reduce the emissions impact of the transport sector in many regions provided that the grid electricity is effectively a cleaner source of transportation fuel than gasoline or diesel fuels. This means that the fuel mix used in electricity generation has to produce fewer emissions than the average

emissions of a conventional gasoline car. As a comparison to a HEV, a PHEV

may offer:

• 25–55% reduction in NOx,

• 35–65% reduction in greenhouse gases, and

• 40–80% reduction in gasoline consumption

Specifically with regard to greenhouse gas emissions, one of the great advantages
to power the vehicle may come from any combination of energy sources includin
wind. In such a case, PHEVs greenhouse gas emissions would be close to
zero. Therefore, in order to reap the full environmental benefits of PHEVs,
their market uptake should be ideally combined with the penetration of zero
emission electricity generation technologies.

There are currently three main designs of PHEVs. These are the series, the parallel and the series/parallel designs. In the series design, the vehicle's wheels are only rotated by the electric motor and not the ICE. The ICE is only used to turn a generator which in turn supplies electrical power to the electric motor system which provides driving power. The battery can store any excess charge produced by the engine. In the parallel design, which is very similar to a HEV design, both the engine and the electric motor can drive the vehicle's wheels independently or even simultaneously through mechanical coupling.

Finally in the series/parallel hybrid design the vehicle has the flexibility to operate in either series or parallel mode.

Regardless of the design, PHEVs may offer two basic modes of operation.

These are the:

• charge–depleting mode, and

• charge–sustaining mode.

Variations or combinations of these two modes that may be additionally available in some PHEVs are termed blended mode and mixed mode. These modes manage the vehicle's battery discharge strategy and their use has a direct effect on the size and type of battery required. The charge depleting mode, also used in FEVs, allows a fully charged PHEV to operate exclusively

on electric power until its battery state of charge is depleted to a predetermined level, at which time the vehicle's ICE will be engaged.

A slight variation of the charge–depleting mode is the blended mode of operation, where the ICE is engaged prior to the battery depletion level being reached. The blended mode is employed by PHEVs which do not have enough electric power to sustain high speeds, or speeds above a certain value, without the help of the ICE. A blended operation mode can typically increase the distance travelled by a fully charged PHEV compared to charge–depleting mode alone.

The charge–sustaining mode is identical to the mode used by HEVs and combines the operation of the vehicle's two power sources in such a manner that the vehicle is operating as efficiently as possible without allowing the battery state of charge to move outside a predetermined narrow band. If the mixed mode of operation is available, then once a PHEV has exhausted its electric range in charge–depleting mode, it can switch automatically into charge–sustaining mode.

As an example, a PHEV with an electric range of 32km may begin a trip with 8km of low speed in charge–depleting mode, then get onto a freeway and operate in blended mode for 32km, using 16km worth of electric range with the corresponding economy in fuel. Then, the driver might exit the freeway and drive for another 8km without the ICE until the full 32km of electric range are exhausted. At this point, the vehicle can revert back to a charge–sustaining

mode for another 16km until the final destination is reached. Such a mixed mode trip contrasts to a charge–depleting mode trip, which would be driven first within the limits of a PHEV's battery.

Since batteries are DC devices, while grid power is AC, on–board DC

chargers are mounted inside the PHEV. The charger's power capacity is only limited by practical vehicle considerations such as space and weight. In practice, order to avoid excess weight. Off–board chargers are, therefore, also available which can be as large as needed and mounted at predetermined locations, such as, the garage or dedicated charging stations.

These chargers can handle much more charging power and therefore charge the batteries in less time. However, the output from these chargers is usually DC, thus needs to be regulated to suit the particular vehicle battery voltage requirements. Modern charging stations have a system for identifying the voltage of the battery pack and adjusting the output of the charger accordingly.

PHEVs operating with charge–depleting mode of operation necessitate deeper battery charging, up to 95%, and discharging, up to 80%, cycles comparec

20% depth of discharge, affords the battery a very large number of lifecycles, in contrast to a PHEV. In addition, PHEVs require larger battery energy potential to allow for extended electric travelling ranges. PHEVs, therefore, require durable and larger battery types, able to withstand deep discharges while at the same time offering the highest possible number of full cycles and battery life. Therefore, design issues and trade–
offs between battery life, capacity, energy, power, weight and, most importantly, for this type of vehicles. In fact, one of the disadvantages of PHEVs compared to HEVs is the unavoidable increased cost of the battery pack since this has to necessarily be larger in size and heavier. Essentially, the optimum battery size for a PHEV depends whether the aim is to reduce gasoline consumption,

battery maintenance costs or vehicle emissions. Also, battery size would criticall between successive battery charges.

Overall, two types of batteries would be suitable for use in PHEVs. These are the nickel cadmium (NiMH) and the lithium–ion (Li–ion) batteries. NiMH

offer inferior energy and power densities than Li-ion batteries, translated to lower electric travelling range and lower maximum vehicle speed and acceleratio sustain higher number of lifetime cycles for deep discharging up to 80%, than Li–ion. NiMH battery can achieve 4000 cycles when discharged to 80% depth of discharge while to achieve the same number of cycles, a Li–ion battery can only be discharged to approximately 50% depth of discharge. This can effectivel to last the lifetime of the PHEV, estimated to require at least 4000 cycles.

Despite this, however, the current technology for PHEVs is based on the Li-ion battery. The reason is that advanced Li–ion battery technology is under significant development and can offer extended energy densities by both mass and volume, and battery life expectancy. This is translated to higher electric travelling ranges and maximum top speeds. A typical electric travelling range achievable is approximately 20–60km with a maximum speed of 160km/h.

The electric travelling range is supplemented by an additional gasoline–only range to reach a total travelling range of 600–900km. Naturally, the electric travelling range potential of a specific PHEV determines the charging power

consumption of the vehicle. It is generally reported that the typical power consumption of PHEVs is around 0.125kWh/km. More specifically, it has been estimated that 8kWh are required to fully charge a PHEV after a 64km trip.

8.4.3 Full electric vehicles

FEVs are powered only by an electric motor or a traction motor rather than a gasoline ICE. Vehicles powered by fuel cells are also considered to be electric vehicles. Electricity is typically generated by on–board rechargeable battery packs and in some cases through the use of capacitors or flywheels. The charging of the battery can be made in way similar to those of PHEVs, i.e., either in standard home electricity outlets or in external dedicated charging stations.

As is the case with HEVs and PHEVs, FEVs have the potential to provide a significant decrease of harmful greenhouse gases emissions of the transport sector compared to conventional ICE vehicles. In fact, the level of emission reductions from FEVs is potentially much higher than that of PHEVs. This of course is critically dependent on the efficiency and on the emissions intensity of the electricity generation system in the specific region where the vehicle will be recharging its battery pack. Aside from the potential emissions advantage, FEVs also exhibit certain advantages in performance compared to conventional gasoline vehicles. These advantages are the result of their built-in high power battery packs. Such battery packs drive electric motors with inherently higher torque in lower vehicle speeds than ICE meaning that FEVs can be much quicker and accelerate from rest faster than conventional vehicles without using any transmission or clutch systems. However, a disadvantage of FEVs that is sometimes overlooked is that the absence of an ICE minimizes the available heating capability of the vehicle’s internal heating system. This could prove to be a significant factor in colder climates that needs to be addressed.

Today a number of FEVs are available in the automotive market. The most recently manufactured FEVs use state–of–the–art Li–ion battery packs and have therefore improved performance compared to NiMH vehicles or older technology Li–ion batteries. A typical FEV has a range of approximately 120–

390km, and a top speed of 200km/h.

The basic systems of a FEV include the electric motor, the battery pack and the electric motor controller. Under normal operation, the motor con-

troller is powered by the battery pack and delivers regulated and controlled power to the electric motor in order to turn the vehicle's wheels. The amount of power, or voltage, to be delivered to the motor by the controller is determined l variable resistors. At any given instance, the relative resistance of these resistors p be delivered to the electric motor. The controller can deliver zero power, or zero voltage, when the car is stopped and the accelerator is not pressed at all, full power, or full battery voltage, when the driver fully presses the pedal, or any intermediate power level in between.

For example, when the accelerator is pressed at 50% the controller chops the full battery voltage at a very high frequency to create an average voltage deliv ping/pulsing is achieved via a system of on/off switches built in the motor controller system. In the case of the 50% pressed accelerator pedal, full voltage p remaining 50% of the time. Most controllers operate at a frequency of 15kHz since at such high frequencies the controller pulsing is not audible to human ears.

A FEV could be using either a DC or an AC electric motor. A DC motor would typically be in the 20–30kW range and require full battery voltage of up to 200V. Such a motor is coupled to a DC controller which could be in the 40–60kW range. An AC motor uses a three–phase motor running at 240V AC

with a 300V battery voltage and typically has higher rated power. An AC

motor/controller system is more complicated than the respective DC system due to the fact that the voltage received by the controller from the batteries is DC. Essentially the AC controller uses six sets of power transistors to convert the 300V DC into 3–phase 240V AC.

In contrast to PHEVs, FEVs need to operate their battery across the whole range of vehicle speeds since no ICE exists. In addition, in order to minimize FEV driver insecurity concerning limited electric travelling range, the battery energy potential needs to be high enough to guarantee at least a minimum driving range that would be sufficient to cover a daily routine driving. These factors provide the need for high–power, high–energy battery packs which would be able to withstand high discharging and high charging levels and also be reasonably light. However, an increased battery energy density would also

increase charging times considerably. Such features are only available through

either NiMH or Li–ion batteries, which however come at a much higher cost.

The cost of batteries is the most significant parameter contributing to the high cost of FEVs today and represents the most important obstacle to the full commercialization of FEVs.

The short driving range and the cost of battery system explain the increased focus FEVs. Compared to batteries, fuel cells can be smaller, lighter and instantly rechargeable. Fuel cell vehicles can be powered by chemical reactions in a fuel cell that create electricity to drive very efficient electrical motors. Finally, fuel cells are using hydrogen, have none of the environmental problems associated with electric power consumption. Potentially, the atmospheric pollution could be, therefore, minimal provided that hydrogen is produced by electrolysis using e

In addition to the main battery pack, most FEVs have another battery on board. This is the standard 12V lead–acid battery that every conventional car has. The 12V battery provides power for accessories, such as, radios, air bags, headlights, wipers, power windows, fans and instruments. Since all of these devices are readily available and standardized at 12V, it is easier from an economic standpoint for an electric car to use them and, therefore, a FEV

has a standard 12V lead–acid battery to power all the accessories.

To keep this auxiliary battery charged, a FEV also has a converter from DC to DC. This converter takes in the DC power from the main battery, e.g., at 300V, and converts it down to 12V to recharge the accessory battery. When the car is on, the accessories are powered from the DC–to–DC converter, but when the car is off, are powered from the 12V battery as in any gasoline–

powered vehicle.

8.4.4

Comparative assessment

FEVs operate only on battery charge and therefore always employ the charge depleting mode of operation requiring high power, high energy battery packs primarily offered by Li–ion batteries. On the other hand, PHEVs offer the possibility of on–board battery charging and the option of charge depleting or charge sustaining modes of operation. Therefore, their demands on battery performance are less strict compared to FEVs and can be satisfied by both Li–ion and NiMH batteries. Finally HEVs, which were the first type of electric vehicles to be manufactured, offer higher travelling range compared to PHEVs

and FEVs due to the existence of the ICE.

Essentially, there are two efficiency indicators that are useful to evaluate the fuel economy and the tailpipe emissions of electric vehicles. The first is the tank–to–wheel efficiency and the second is the well–to–wheel efficiency. The tank–to–wheel efficiency refers to the operating efficiency of the car itself and provides the car's actual fuel economy. The well–to–wheel efficiency is a more comprehensive efficiency indicator since it includes, apart from the tank–to–wheel efficiency, the efficiency of the fuel/electricity production infrastructure from the oil–well to the tank.

As an example, a comparison of the tank–to–wheel and the well–to–wheel efficiencies of a conventional gasoline vehicle and a FEV will be described.

Typical tank–to–wheel efficiency of any gasoline vehicle is primarily limited by the ICE peak efficiency, which is theoretically around 38%. In reality however, conventional gasoline vehicle efficiencies would be much less, even approaching 15–20%, depending on the mode of driving of the vehicle. Tank–to–wheel efficiency of a FEV is limited primarily by the energy cycle, charging and

discharging, of the battery. FEVs using Li–ion batteries can reach efficiencies of at least of 75%, while with lead–acid batteries efficiency can drop to 60%.

This is of course still significantly higher when compared to the efficiency of ICE based conventional gasoline vehicles.

Essentially, the efficiency gains in FEVs are achieved due to the better performance of the electric motor instead of the ICE at lower speeds and due to the fact that FEVs do not consume energy when not moving, unlike ICE which continue running even during idling. However, when considering the well–to–

wheel efficiency of these two types of vehicles, the situation is different. In this case, the difference in efficiency is significantly reduced. The reason is that the generation of electricity necessary for FEVs battery charging, relies on fossil fuels through the use of power generators operating at efficiencies between 30–60%. The final difference in efficiency between a conventional ICE vehicle and a FEV would then depend on the fuel mix and type of generators used in the electricity generation system of the specific region or country where the FEV will be charging its battery.

Generally, the tank–to–wheel efficiency is used to provide a fuel economy comparison for vehicles of the same category type. It is also used for the same purpose to compare vehicles across different vehicle category types, i.e., for conventional gasoline vehicles, FEVs, or PHEVs. The well–to–wheel efficiency is however necessary in order to provide a meaningful comparison of vehicle

tailpipe emissions across these different types of vehicle categories.

8.4.5 Grid to vehicle charging

Grid to vehicle charging (G2V) refers to the process of battery charging of

the electric vehicles from the electricity grid infrastructure. Clearly, electric vehicles such as PHEVs and FEVs need to charge their battery packs through the electricity grid in order to be able to move. Battery charging is mostly achieved through the use of conventional household outlets. However, high charging times and the need for vehicle charging in outside locations for more frequent and quicker charging has resulted in the advent of publicly available charging stations. These stations can be independent or belonging to a network of stations and may offer state–of–the–art smart grid applications.

Recharging the battery from a regular household charging system has the advantage of convenience, however the disadvantage is increased charging time and the possible absence of electrical outlets at convenient locations for charging

outlet with a 15A circuit breaker, although the maximum current to be drawn by the vehicle in practice may be limited to less than 15A. Typically the power output from such outlets is between 1.4–1.5kWh. Therefore for a typical FEV, a 12 to 15kWh full battery recharge would take 10 to 12 hours.

For European household outlets the typical respective ratings are 220/240V

at 30A supply. However, the maximum power that can be eventually drawn by the vehicle will limited by the maximum power rating of its on–board battery charger. Despite this, a 220V outlet would allow significantly faster charging than the 110V and for FEVs with a 3.3kWh on–board battery charger, it could fully recharge a 12 to 15kWh battery pack in 4 to 5 hours.

In order to reduce full battery charging time, some FEVs that possess high energy density batteries, have the option of proprietary, custom–made charging units which allow faster charging. These are DC fast charging units with a voltage of 480V DC and 125A charging current, or a 500V DC unit.

Other designs for faster charging include wall–mounted AC charging units allowing higher current circuit breaker ratings, e.g., 240V 70A. One of the disadvantages of frequent fast–charging appears to be that the gradual battery capacity loss can be as much as 10% higher in a 10 year period than in the case of normal charging with the 220V home outlet.

The electric vehicle network is a proposed infrastructure system of publicly–

accessible charging stations and possible battery swap/switch stations to charge electric vehicles. Government, car manufacturers, electricity utility companies, and charging infrastructure providers have entered into many agreements to create such networks. Already, a number of charging stations are planned or in place in countries such as Australia, China, Denmark, Norway, France, Italy, Estonia, Germany, Switzerland, Ireland, Netherlands, Poland, UK, Spain, Israel and the USA.

In Germany and France, which together with the UK are currently the leading European countries in terms of number of charging stations, the major electricity utility companies have entered into partnerships with electric car manufacturers to develop further the infrastructure of charging stations. As an example is the RWE AG–Daimler AG partnership which has already set up of 60 charging stations in Berlin servicing the needs of over 100 e–Smart FEVs. Other similar alliances include EDF–Toyota, EDF–Renault/Nissan and Vattenfall–BMW.

The charging networks that are already in place today offer conventional AC charging outlets, based on the prevailing national vehicle charging specificati is transferred to the vehicle's on–board charger. In the USA, the AC charging standard used is the SAE J1772 standard, which is the same standard used in electrical outlets in homes in the USA and Japan, and is either 120V 16A, called Level 1, or 220V 32A, called Level 2 outlets. In Europe, the AC charging s Australia, the standard used is the AS 3112 with 230V 15A outlets. Finally, in the UK, charging stations use the BS 1363 standard 230V 13A outlets.

In contrast to conventional AC charging, the option of fast charging is offered onl on the specific country or region and the specification it adopts. In any case, fast charging is usually denoted as Level 3 charging in the USA and as Mode 3 (AC fast charging) or Mode 4 (DC fast charging) in Europe. During fast charging, the energy is typically transferred to off-board charger and requires devoted connectors.

These connectors usually provide additional features during the charging

process, such as inability of the vehicle from moving during charging, or option f grid scenarios.

Taking this idea further, the electric vehicle recharging network can have an intelligence built into it, through tailored software, allowing drivers to find

out where their nearest charging point is, to evaluate how much they need to recharge given the current state of their battery, and when would be the most cost–effective time for them to recharge given current prices offered by the electricity grid.

In Europe, fast charging is usually AC through Mode 3 standard which is 400V 32A (in the UK CEE blue is also used with 230V 32A) and Type 2 connector. Ireland applies a DC fast charging using the Charge de Move (CHAdeMO) protocol with voltages from 300 to 500V DC 125A. However, in the absence of a universal connector/outlet standard or specification, most fast charging outlets tend to vary from country to country and be custom made to suit the specific vehicle model of the manufacturer participating in the specific network.

Another alternative to achieve rapid recharging of completely discharged battery packs is the battery replacement or battery swapping option. In this way, instead of recharging the battery it could be mechanically replaced on special stations in just a few minutes. This alternative could apply to batteries with very high energy densities that require significant time to recharge. In the future, batteries with the greatest energy densities, such as metal–air fuel cells, which cannot be recharged in a purely electric way appear to be promising candidates for battery swaps.

Taking into consideration the current ranges of electric cars, it is clear that until a charging infrastructure (even one that consists of simple 240V

electrical outlets in convenient places) is developed, electrical vehicles will

remain best suited for local driving in short ranges around the home. In order to facilitate the penetration of electric vehicles as a competitive alternative to conventional vehicles, mass provision of charging points and networks must precede consumer availability of electric vehicles. The geographic location of the charging points would play a critical role in the adoption of electric vehicles in each area, especially FEVs, and would have to take into consideration the concentration of both residential and office areas.

8.4.6

Vehicle to grid electricity

Vehicle to grid (V2G) electricity refers to the technology of bidirectional flow of electricity between the electric vehicle and the grid. V2G enabled vehicles can therefore transfer electricity both to and from the power grid as necessary.

If this technology is in place, electric vehicles could use their excess battery

capacity to export power back to the grid, and can potentially assist and supplement electricity supply during peak hours. This would be beneficial to the electric utility, as it would allow for lower electricity generation costs since the more expensive peaking units would be committed to a lesser extent. If this export of electrical power is combined with off–peak import (charging) it would potentially even out the demand for electricity which would be financially beneficial to both the electric utilities and the electric vehicle owners. For the utilities a smoother demand curve would translate to more economic unit commitment and economic dispatch.

The vehicle owner would stand to gain from the difference of buying electricity (peak rates, while selling it to the grid at higher
peak demand rates. In addition, the exported electrical power can be used also for the optimization of reactive power requirements to the distribution network ar in a manner very similar to distributed generation as it supplies power when

power is needed and consumes power when there is an excess. In fact, electric ve sources with generation profiles that do not match demand profiles, such as wind power.

Such an export of electrical energy from electric vehicles could take place either in the G2V charging stations themselves or in private home outlets.

The intelligent connection of the charging station to the grid can allow vehicle owners to communicate with the grid operator and inquire when would be optimal times not just for “downloading current” from the grid (charging or recharging batteries) but also for “uploading current” to the grid (discharging batteries) when convenient to do so.

The electrical energy has to be exported to the grid via permission of the grid operator who would have to ensure the balance of load across the network.

In cases of energy exported from vehicles using the single–phase home outlets, the issue of maintaining the three–phase balance of load in the distribution network would become more complicated.

V2G technology needs to offer the possibility to recharge the electric vehicle in order to ensure that the vehicle will be able to reach its next destination using electric energy. Hence vehicles should be able to quit V2G services in order to recharge sufficiently before departure. Furthermore, widespread use of V2G services can lead to critical states of the distribution network, such as islanding.

Currently the base standards and regulation framework do exist to ensure the tran FEVs. However, if the market is to expand to include a significant share of electric vehicles, standards and regulation will need to be expanded in order to incorporate the entirety of the system impacts of the electric vehicles, from generation impacts to the V2G smart–grid to the end–user.

Fundamentals of Energy Regulation

Chapter 9

Pricing Environmental

Pollution

The modern world depends on fossil fuels. I indeed it can be convincingly argued that we live in the hydrocarbon age. However, fossil fuels are finite and the world's energy and environmental future depends on a gradual change to a mix of non–fossil fuel sources, such as RES technologies. In order to understand the societal value offered by clean energy technologies, it is useful that we understand the environmental and political consequences of today's modern energy infrastructure. The extraction, production, distribution, and consumption of fossil fuels greatly affect the quality of the natural environment on our planet. These problems affect our air quality, ecosystems, land and material resources, human health, and global stability, as well as the aesthetic, cultural and recreational values of affected regions.

Energy production and usage, particularly through fossil fuels, has become the dominant force related to environmental destruction and global climate change on the planet. CO2 emissions are the principal contributions to global climate change. Energy usage is the largest contributor to CO2 emissions and includes all aspects of power production and utilization.

Environmental cost will play an increasing role in shaping future energy policy. Cleaning up the business of power supply has been declared a fundamenta major contributor. The task that energy policy makers are facing is how to best go about the job of reducing pollution in electricity generation since in 177

most countries environmental costs are not reflected in the market price of the end product.

9.1

Climate change

The world has warmed by an average of 0.76oC since pre–industrial times and this temperature rise is accelerating. Today sea levels have risen almost twice as fast as during the previous three decades. Man–made emissions of greenhouse gases are causing these changes.

Without action to limit future emissions, the global average temperature is likely to increase further by 1.8oC to 4oC this century, and in the worst case scenario by as much as 6.4oC. The EU considers it vital to prevent global warming of more than 2oC above the pre–
industrial level. There is considerable scientific evidence that beyond this thresho
catastrophic changes could occur. However, climate change is a global challenge

EU recent analysis shows that for the world to have a fair chance of keeping the a
greenhouse gases will have to be stabilized by around 2020, then reduced by at least 50% of 1990 levels by 2050. This ambitious goal is both technically feasible and economically affordable if major emitters act urgently. The benefits o
evidence of the cost of climate change based on recent studies reaffirms the enormous costs of failing to act. These costs, not only economic but also social and environmental, will fall especially heavily on the poor, in developed and developing countries alike.

Allowing climate change to continue unabated would also have serious regional and global security implications. Climate change is already having strong effects on ecosystems, water resources and coastal zones across the world. It is affecting people in various ways, including higher mortality during heatwaves, water scarcity, and changes in the distribution of diseases carried by vectors such as ticks and mosquitoes.

Recent EU analysis shows that the investment needed to achieve a low–

carbon economy would cost only around 0.5% of world GDP between 2013

and 2030. The emission cuts needed to keep within a 2oC temperature rise would reduce average gross domestic product (GDP) growth by less than 0.12%

points per year up to 2050. This is a small price to pay to insure humanity against dangerous levels of climate change. And this figure does not even take into account the benefits of cutting emissions, such as reduced damage from avoided climate change, greater energy security, and healthcare savings from less air pollution.

9.2 Accounting for environmental cost

Environmental costs, or at least some elements of it, are difficult to quantify, but t the broad definition of environmental costs there are widespread variations in defining the boundaries. Arguments for the environmental costs attributable to oil fired generation range from supertanker spillages, to a substantial proportio energy are infernally complicated. For simplification they can, however, be divided into three broad categories:

(a) hidden costs borne by governments,

(b) costs of the damage caused to health and the environment by emissions other than carbon dioxide, and

(c) the costs of global warming attributable to carbon dioxide.

The first category includes the cost of regulatory bodies, pollution inspec-torates, energy industry subsidies and research and development programmes.

The second category, costs due to emissions which cause damage to the environment or create health problems, make up 10–20% of the environmental cost of power generation, depending on the fuel used. They include a wide range of environmental effects, including damage from acid rain and damage to health from sulphur oxides and nitrogen oxides from thermal power stations.

The cost of damage to health is estimated by calculating the loss of earnings and cost of hospitalization of people susceptible to respiratory diseases.

Other costs included in the damage and health category are power industry accidents, whether they occur in coal mines, on offshore oil or gas rigs, or in

nuclear plants. The probability of a nuclear accident in Western Europe might be extremely low, but should a catastrophic failure occur the costs would be undeniably huge.

The third category is by far the largest. Environmental costs due to greenhouse ga

This category accounts for some 40–80% of the hidden costs of the world's consumption of electricity. It is, also, the most contentious area of the environme implications of global warning is huge in the studies conducted to date. Costs associated with climate changes, flooding, changes in agricultural patterns and other effects all need to be taken into account.

Clearly, discussion of the make–up of environmental costs is endless. What is important is that governments and regulators should not allow the uncertainty s existence when energy options are being considered. To aid decision makers, studies over the past eight years have identified and quantified the pollution caused by the electricity business. Importantly, they have also tackled the job of pricing that pollution through the so–
called monetarization of environmental costs.

Many studies have looked at overall damage potentials on health and the environment, assigning a cost penalty to each generating technology, depending o difference in environmental costs between, say, coal and natural gas, to be easily compared. Another approach to monetarization, from a slightly different ar carbon dioxide emissions and up to 25000e/t for sulphur dioxide emissions.

Table 9.1: Environmental costs estimates

Category

Coal

HFO

Natural gas

Nuclear

(ec/kWh)

(ec/kWh)

(ec/kWh)

(ec/kWh)

Human health,

0.70–4.00

0.70–4.80

0.10–0.20

0.03

accidents

Crops, forestry

0.17–1.50

1.60–1.70

0.08–0.09

small

Buildings

0.15-5.00

0.20–5,00

0.05–0.18

small

Disasters

–

–

–

0.11–2.50

Global warming

0.50–24.00

0.50–1.30

0.30–0.70

0.02

Indicative totals

2.05–34.5

3.00–12.80

0.53-1.17

0.16–2.55

Since the quantities of each pollutant emitted are well known for the differing fue
unit of electricity. Coal fired generation produces the most pollutants, about
one kilogram of carbon dioxide per kWh, plus sulphur dioxide and other pollutan

is pushed up and other clean technologies become relatively cheaper.

9.3

The carbon tax concept

In the course of the ongoing deregulation of the energy sector, existing energy policies and practices that encourage more environmentally benign energy resour order to secure the gains achieved in the past and to make the further progress needed for sustainability. Carbon taxes can help fill this void. Through raising en fuel combustion would
discourage energy use and induce some switching to less carbon–intensive fuels.

While traditional taxes are decreased, the introduction of pollution taxes would not only decrease pollution, but also provide the revenues needed to sustain the legitimate purposes of a tax system. In short, carbon tax reduces taxes on goods (work effort, business activity) and increases taxes on bads (pollution, energy use). It offers the promise of a simultaneous improvement of economy and environment. However, carbon tax is not a panacea for all social ills. Its scope is constrained by the societal objectives of a tax system and its functional requirements, which pollution taxes alone cannot fulfil. These include equity (whose main vehicle is a progressive personal income tax), and a reliable and steady flow of revenues, which attenuates the impacts of the business cycle.

Thus, a significant portion of the current tax system must be maintained.

Moreover, as carbon tax can introduce an additional source of revenues, it invites discussion of the uses of those revenues, in addition to tax reductions, such as for technology development and diffusion, training and skills developme tax, based on relatively modest price elasticities of demand, could be amplified by the use of some of its revenues to support efficiency improvements, infras-

tructure, and market transformation. Thus, while carbon tax appears as a highly promising policy strategy, it cannot solely be relied on for environmental p

set–asides, standards, public investments, etc., which can add to, and amplify its environmental benefits, and by other policies aimed to enhance economic productivity.

The revenues from carbon taxes could provide the means for simplifying existing economic–
development incentives. Carbon taxes with offsets in traditional taxes, as the core development policy, could give
a clear and consistent signal to businesses. Some countries are already engaged in policies to foster the greening of businesses. Carbon tax could enhance this policy goal, wedding environmental and economic policy objectives.

The net effect of a generally more favorable business climate is likely to be positive. Some energy–intensive businesses might very well benefit from the technological advancements that higher energy prices would likely trigger.

It is common that energy–
efficiency investments improve overall productivity and thus lower not only energ related costs. Indeed, some countries already maintain economic development pro business productivity through counseling in eco–efficiency (which encompasses energy efficiency and pollution prevention).

A carbon tax would increase the cost of fossil fuels and electricity and generate tax revenues. Electricity producers, industrial and commercial enterprise ways:

(a) by reducing energy–using services and activities,
(b) by investing in energy saving technologies, and
(c) by switching to less carbon–intensive fuels.

The magnitude of these responses is a function of how easily consumers can change their energy–use patterns, the cost and availability of more energy–

efficient equipment and appliances, and the ability of consumers to switch to less carbon–intensive fuels and the technologies that can use them.

For example, in the electric sector, these could be more judicious use of lighting, switching from incandescent to compact fluorescent bulbs, and a shift from coal and oil–fired generation to gas, wind and other low–carbon–intensity

technologies. For the commercial and residential sectors, the impacts could be improved thermostat controls, tighter building shells, and a shift from oil to gas. For industry, these could be output changes, process–technology changes (e.g., co–generation), and shifts to gas or biomass. Industry could also respond by a reduction in electricity demand through the use of more efficient lighting, motors, and other equipment in buildings and industry.

The biggest concern voiced about a policy of carbon taxes with other tax reductions is that such a policy would constitute a disadvantage to in–country businesses versus competitors in other countries. This is a concern for a small number of energy–intensive industries, and needs to be addressed through special mechanisms designed to attenuate the negative impacts of carbon tax on these industries.

Notwithstanding this concern, cost effects suggest that many industries would indeed experience a net cost decrease from the policies. To the extent that trade flows respond to cost differentials, this would suggest that industries could gain market share in response to the tax policies.

The more important point, beyond the scope of economic analysis, is that carbon tax has the potential to give direction to the technological changes that the economy is undergoing, by steering it onto a path of less carbon–intensive, clean, and future–oriented methods of production and consumption. It is also important that the design of a specific carbon tax takes into account a range of equity issues. These include maintaining the society's commitments to progressivity in the modified tax system as well as transitional assistance to workers and communities.

It is evident that a carbon tax would likely help meet national climate policy goals energy generation. Also, it would provide the opportunity for a consistent economic development policy by yielding revenues so as to modernize infrastruc improving labor skills and foster technological progress and the development of niche markets.

9.4

Emissions trading

Emissions trading is an administrative approach used to control pollution, by providing economic incentives for achieving reductions in the emissions of pollutants. It is sometimes called cap–and–trade. A central authority (usually a government or international body) sets a limit or a cap on the amount of a pollutant that can be emitted. Companies or other groups are issued emission permits and are required to hold an equivalent number of allowances (or credits) which represent the right to emit a specific amount. The total amount of allowances and/or credits cannot exceed the cap, limiting total emissions to that level. Companies that need to increase their emissions must buy credits from those who pollute less. The transfer of allowances is referred to as a trade. In effect, the buyer is paying a charge for polluting, while the seller is being rewarded for having reduced emissions by more than was needed.

Thus, in theory, those that can easily reduce emissions most cheaply will do so, achieving the pollution reduction at the lowest possible cost to society.

There are active trading programs in several pollutants. For greenhouse gases the largest is the EU emissions trading system (ETS). In the United States there is a national market to reduce acid rain and several regional markets in nitrous oxide. Markets for other pollutants tend to be smaller and more localized.

Carbon trading is sometimes seen as a better approach than a direct carbon tax or can be cheaper and politically preferable for existing industries because the initial allocation of allowances is often allocated with a grandfathering provision most of the money in the system is spent on environmental activities, and the investment directed at sustainable projects that earn credits in the developing world.

The overall goal of an emissions trading plan is to reduce emissions. The cap is usually lowered over time, aiming towards a national emissions reduction t causing a net reduction in emissions each time a trade occurs. In many cap

and trade systems, organizations which do not pollute may also participate, thus environmental groups can purchase and retire allowances or credits and hence drive up the price of the remainder according to the law of demand.

Corporations can also prematurely retire allowances by donating them to a nonprofit entity and then be eligible for a tax deduction.

Because emissions trading uses markets to determine how to deal with the problem of pollution, it is often touted as an example of effective free market environmentalism. While the cap is usually set by a political process, individual c

In theory, firms will choose the least–costly way to comply with the pollution regulation, creating incentives that reduce the cost of achieving a pollution reduction goal.

9.5 The EU ETS

The EU ETS is the largest multi–national, greenhouse gas emissions trading scheme in the world and was created in conjunction with the Kyoto Protocol.

It is based on a recognition that creating a price for carbon through the establishm way for countries to move towards the low–carbon economy of the future and achieve the deep reductions in global greenhouse gas emissions that are needed to prevent climate change from reaching dangerous levels.

The system will allow the EU to achieve its emission reduction targets.

The EU ETS is based on six fundamental principles.

- It is a cap–and–trade system,
- Its initial focus is on CO_2 from big industrial emitters,

• Implementation is taking place in phases, with periodic reviews and opportunities for expansion to other gases and sectors,

• Allocation plans for emission allowances are decided periodically,

• It includes a strong compliance framework,

• The market is EU–wide but taps emission reduction opportunities in the rest of the world through the use of the clean development mechanism (CDM compatible systems in third countries.

At the heart of the EU ETS is the common trading currency of emission unit allowance (EUA). One EUA gives the right to emit one tonne of CO_2.

Member states are required to draw up national allocation plans covering each trading period. These plans allocate to each installation in the system EUAs to emit a certain level of CO_2 per year. Decisions on the allocations are made public.

The limit or cap on the number of EUAs allocated has created the scarcity needed for a trading market to emerge. Companies that keep their emissions below the level of their EUAs can sell their excess EUAs at a price determined by supply and demand at that time. Those facing difficulty in remaining within their emissions limit have a choice between taking measures to reduce their emissions (such as investing in more efficient technology or using a less carbon–intensive energy source), buying the extra EUAs they need at the market rate, or a combination of the two, whichever is cheapest. This ensures that emissions are reduced in the most cost–effective way.

The legal framework of the EU ETS does not lay down how and where trading in EUAs should take place. Companies and other participants in the market trade directly with each other or buy and sell via a broker, exchange or any of the other types of market intermediary that have sprung up to take advantage of this significant new market. Trading in EUAs takes place at

several organized exchanges in Europe, and a number of other intermediaries (e.g., brokers, etc.) are active in the market.

The price of EUAs is determined by supply and demand as in any other market. The EU ETS has thus established itself as the engine of the global carbon market that is emerging as a powerful tool to combat climate change.

The system is generating important knowledge for the successful design and operation of carbon trading systems elsewhere and international emissions trading.

EU ETS Phase I (2005–2007) commenced operation in January 2005 with all member states of the EU participating. The program caps the amount of CO_2 that can be emitted from large installations, such as power plants and carbon intensive factories and covers almost half of the EU's CO_2 emissions.

Phase I permitted participants to trade amongst themselves and in validated credits from the developing world through Kyoto's CDM. During the first year of Phase I operation, 2005, at least 270 million allowances (tonnes of CO_2) were traded, with a value of around e5 billion. In 2006, trading volume rose to more than 800 million allowances, and in 2007 this level was reached after

only seven months of the year. European trading constitutes some 80% of the global turnover of CO_2 allowances and credits, which was valued at e14.6

billion in 2006.

Biography

Dr. Andreas Poullikkas holds a Bachelor of Engineering (B.Eng.) degree in mechanical engineering, a Master of Philosophy (M.Phil.) degree in nuclear safety and turbomachinery, a Doctor of Philosophy (Ph.D.) degree in numerical analysis and a Doctor of Technology (D.Tech.) higher doctorate degree

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• Introduction to Power Generation Technologies (ISBN: 978-1-60876-472-3)

• Sustainable Energy Policymaking for Cyprus (ISBN: 978-9963-7355-6-3)

• Energy Union and Strategy for Cyprus (ISBN: 978-9963-7355-7-0)

• Sustainable Energy Development for Cyprus (ISBN: 978-9963-7355-3-2)

• The Cyprus Energy Future (ISBN: 978-9963-9599-4-5)

He is, also, a referee for various international journals, serves as a reviewer for the evaluation of research proposals related to the field of energy and a coordinator of various funded research projects. He is a member of various national and European committees related to energy policy issues. He is the developer of various algorithms and software for the technical, economic and environmental analysis of power generation technologies, desalination technologi

Fundamentals of Energy Regulation provides an insight to the wide range of topics necessary for energy regulators. Is a complete introduction to the world of energy regulation and provides the fundamental aspects of each energy regulation topic. Introduces important regulatory topics and features explanations of key economic and regulatory concepts. Covers emerging issues associated with restructured electric energy and capacity markets as well as international practises affecting the natural gas and electric industries. Provides the various aspects and steps of managing the transition to energy market competition and for the development of energy tariffs.

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